RECEIVED Pamela Jones Digitally signed by Pamela Jones Date: 2022.01.20 17:11:47 -07'00'
By Environmental Improvement Board at 5:11 pm, Jan 20, 2022

STATE OF NEW MEXICO
BEFORE THE ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF:

PROPOSED NEW REGULATION
20.2.50 **No. EIB 21-27 (R)**
Oil and Gas Sector – Ozone Precursor Pollutants

CLOSING ARGUMENTS BY NEW MEXICO OIL AND GAS ASSOCIATION

Pursuant to the "Procedural Order on Post-Hearing Process" filed in this matter on November 19, 2021, the New Mexico Oil and Gas Association ("NMOGA") hereby submits its closing arguments, proposed statement of reasons, and an annotated redline in the EIB 21-27(R) proceeding.

The New Mexico Environment Department ("NMED" or "Department") proposes that the New Mexico Environmental Improvement Board (the "Board") adopt a new 20.2.50 NMAC to require additional control of ozone precursors emitted by oil and gas owners and operators located within areas of the state where ozone concentrations exceed ninety-five percent of the primary national ambient air quality standard.

NMOGA is a coalition of more than 1,000 oil and natural gas companies. Industry suppliers, and individuals operating in the state of New Mexico and has been engaged in this rulemaking effort since its inception. NMOGA members include all facets of oil and gas production, transportation, and delivery. NMOGA is the oldest and largest organization representing the oil and gas industry in New Mexico. Oil and gas production is the greatest economic contributor to the state of New Mexico, supporting more than 134,000 jobs and $17 billion in annual economic activity. In addition, taxes and royalties from the oil and gas industry account for $5.3 billion in public revenue which is 39% of New Mexico's annual budget, including over $1.4 billion for public schools.

NMOGA's goal is to achieve a workable rule that makes significant progress in reducing ozone precursor pollution. As a representative of so many entities regulated by this rule, NMOGA ask the Board to give serious consideration to its concerns and suggestions.

Table of Contents

I. SUMMARY OF ARGUMENT 5

II. ARGUMENT 10

A. Stringency Relative to Federal Law. The Board Should Carefully Scrutinize All Sections of This Proposal That Are More Stringent than Federal Law and Reject Any Standard Where Public Notice Was Not Provided or Substantial Evidence of Greater Protectiveness Is Not in the Record. 10

B. Economic Reasonableness. The Board Should Reject Proposals That Are Economically Unreasonable to Protect the Contributions the Oil and Gas Industry Makes to the New Mexico Economy. 13

C. Scope, 20.2.50.2 NMAC. The Board Should Not Apply This Rule to Rio Arriba and Chaves County Because These Counties Do Not Have Department Monitors Demonstrating the Design Value Exceeds 95% of The Ozone Standard. 15

D. Applicability, 20.2.50.111 NMAC. The Record Does Not Support NMED's Insistence that Only an Engineer Is Qualified to Calculate Potential to Emit. 17

E. General Provisions, 20.2.50.112 NMAC. The Board Should Memorialize the Department's Commitment to Engage in a Stakeholder Process to Identify Date and Timestamp Technologies and Provide Industry Two Years to Integrate These Technologies. 18

F. Engines and Turbines, 20.2.50.113 NMAC. The Board Should Adopt the Department's Proposal Because It Requires Reasonable and Aggressive Emissions Reductions. 21

G. Control Devices, 20.2.50.115 NMAC. The Board Should Adopt the Department's Control Devices Standard, Except that The Redundant VRU Requirement Is Not Supported By the Record and Should be Rejected. 23

H. Equipment Leaks & Fugitive Emissions, 20.2.50.116 NMAC. 24

i. The Board Should Reject the More Stringent Leak Detection and Repair Thresholds and Frequencies Proposed by NMED and Adopt NMOGA's Proposal Because the Added Stringency of NMED's Proposal Has Minimal Impacts on VOC Reductions and Fails to Account for The Diminishing Returns of Increased Survey Frequency. 24

ii. The Board Should Reject the Proximity LDAR Proposal Because It Is Beyond the Scope of This Rulemaking, Does Not Demonstrably Contribute to The Objective of Attaining and Maintaining the Primary Ozone Standard, and is Not Cost-Effective. 30

I. Hydrocarbon Liquid Transfers, 20.2.50.120 NMAC. The Board Should Adopt the Department's Latest Redline with Minor Revisions Because the Proposal Incorporates Several

Changes Consistent with the Board's Obligation to Consider the "Technical Practicability and Economic Reasonableness" of Its Rules. 35

J. Pig Launching & Receiving, 20.2.50.121 NMAC, and Well Workovers 20.2.50.124 NMAC. The Board Should Reject Standards for Pig Launching & Receiving and Well Workovers Because They Do Not Demonstrably Impact Ozone. 37

K. Pneumatic Controllers and Pumps, 20.2.50.122 NMAC. The Board Should Adopt NMED's Pneumatics Proposal, with Minor Changes to Enhance Workability, and Reject Proposals by Other Stakeholders to Increase the Stringency of Pneumatics Requirements..... 39

L. Storage Vessels, 20.2.50.123 NMAC. The Board Should Adopt NMED's Storage Vessel Proposal, Except that The Threshold for Existing Single Storage Vessels Should Be Increased to 6 TPY........ 44

M. Small Business Facilities, 20.2.50.125 NMAC........ 48

N. Produced Water Management Units, 20.2.50.126 NMAC. The Department Should Exclude Recycling Facilities from the Definition of Produced Water Management Units...... 49

O. Credible Evidence, 20.2.50.127. The Board Should Adopt the Parties' Stipulation. 50

III. CONCLUSION........ 50

I. SUMMARY OF ARGUMENT

Without a doubt, the proposed Part 20.2.50 NMAC is a complex and costly rule. Despite the fireworks at the hearing on the costs, there is not much difference between the industry estimate ($3 billion+ over five years) and the Department's estimate (approximately $1.2 billion) when you consider that industry included all costs while the Department's experts "financed" the costs over 15 years but only reported the first five-year cost. The volatile organic compound (VOC) controls in the rule also contribute limited ozone reduction, amounting to about 0.2 ppb through much of the Permian and perhaps 0.5 ppb in the San Juan basins. As testified at the hearing, changes of over a thousand tons/year of VOC would not affect the modeled results. In such circumstances, the Board has a duty to carefully scrutinize the proposed controls to ensure that they are worth the expenditure of New Mexico's limited time and treasure. In reaching its conclusions, the Board may consider co-benefits, but may not rely on them as the exclusive basis for adopting a provision. With this caveat, NMOGA supports the Department's petition in many respects but proposes several changes to improve the workability of the rule and eliminate costly measures that provide little to no ozone reduction or air quality benefit. For the Board's convenience, these arguments are presented in rule order.

Scope, 20.2.50.2 NMAC. The legislature has limited the applicability of 20.2.50 NMAC[1] to "sources of emissions within the area of the state where the ozone concentrations exceed ninety-five percent of the primary national ambient air quality standard." The Department has selected counties as the "area of the state" underlying this evaluation and the "design value" for comparison against the ninety-five percent threshold. The only monitor in Rio Arriba County has a design

[1] Unless otherwise specified, all references to 20.2.50 NMAC refer to the department's December 16, 2021 proposal. A subsequent proposal was provided on January 18, 2022. Where significant, we have noted changes reflected therein.

value less than 95% of the ozone NAAQS, and Chaves County does not have a design value established. Tr. 1:191:12-18. Because these "areas of the state" do not have design values exceeding ninety-five percent of the primary ozone standard, the Board currently lacks authority to impose 20.2.50 NMAC on sources located within these counties.

Applicability, 20.2.50.111 NMAC. The record does not support NMED's insistence that only an engineer is qualified to calculate potential to emit. The Board should ensure the integrity of potential to emit calculations by simply requiring that the engineer, consultant or inhouse staff be appropriately qualified based on training and experience.

General Provisions, 20.2.50.112 NMAC. While the Department is no longer proposing the impracticable Emissions Monitoring Tagging ("EMT") system, various section of 20.2.50 NMAC continue to require owners and operators to record a date and time stamp, including a GPS display of the location, for certain monitoring events. The Department has committed to identify acceptable technologies within one year.[2] In identifying these technologies, the Department has indicated it will engage with stakeholders and solicit and incorporate feedback. The Board should memorialize this commitment in the regulatory language or statements of reason. In its most recent proposal, the Department has also granted industry two years from the date technologies are identified to finalize implementation.[3] NMOGA asks the Board to adopt this extended timeline, which is responsive to voluminous testimony concerning the impracticality of integrating technologies for an entire industry within a shorter timeframe.

Engines & Turbines, 20.2.50.113 NMAC. While the Department's initial petition imposed unworkable emissions limits on engines and turbines, the Department has now proposed standards that are both aggressive and achievable. The Department has also incorporated several crucial

[2] This is reflected in the Department's most recent redline circulated to parties on January 18, 2022.
[3] This is reflected in the Department's most recent redline circulated to parties on January 18, 2022.

changes that eliminate unenforceable standards, provide flexibility, and ensure environmental protection. These include the exclusion of nonroad engines (20.2.50.113.A), the redefining of construction to exclude relocation and like-kind replacement (20.2.50.7.J), extended implementation timelines (20.2.50.113.B.2 and B.7(a)), an alternative compliance plan option (20.2.50.113.B(10)), an alternative emission standard allowance in cases of technical impracticability or economic infeasibility (20.2.50.113.B(11)), and the incorporation of the short-term replacement engine substitution concept currently authorized in many air quality permits (20.2.50.113.B(12). To ensure engine and turbine standards maintain "technical practicability and economic reasonableness," the Board should finalize the tables and concepts as presented in the Department's and NMOGA's redlines.

Control Devices, 20.2.50.115. NMOGA generally supports the standards for control devices in the Department's latest proposal, except that the record does not demonstrate that the more stringent redundant control requirements under 20.2.50.115.E.1(b) NMAC are more protective of ozone concentrations. The Board should not adopt these requirements.

Equipment Leaks and Fugitive Emissions, 20.2.50.116 NMAC. NMOGA's proposed inspection frequencies and thresholds achieve significant emissions reductions, are supported by the record, and should be adopted by the Board. NMOGA urges the Board to not adopt the Department's proposed thresholds and frequencies under 20.2.50.116 NMAC, which imposes unduly burdensome leak detection and repair requirements that contribute little to the statutorily prescribed goals of ozone attainment and maintenance. The Department's proposed leak inspection frequencies under 20.2.50.116.C(3)(b), (c), and (e) impose a stringency that does not account for the diminishing returns of repetitive inspections and the escalating, exorbitant incremental costs. The proximity proposal under 20.2.50.116.C(3)(e) to require more frequent inspections at well sites within 1,000 feet of an occupied area also miss the mark and is worrying vague. The Board's authority under NMSA 1978, § 74-2-5.C and the notice provided to the public require that standards under 20.2.50 NMAC be targeted at attaining and maintaining the ozone primary standards. The proximity proposal is directed at mitigating impacts from direct emissions, not from ozone, which expert testimony admitted would not form in the 1,000-foot distance prescribed. Testimony of Lee Ann Hill, Tr. 9:2848:10-10:2849:6.

Hydrocarbon Liquid Transfers, 20.2.50.120 NMAC. To ensure the "technical practicability and economic reasonableness" of standards under 20.2.50.121 NMAC, the Board should finalize several changes proposed by the Department and NMOGA. These include excluding liquid transfers involving produced water, excluding production facilities and associated tank batteries delivering liquids directly to pipelines, excluding sources that perform less than 13 loadouts per year, allowing semiannual inspections at unstaffed locations, and applying the extended implementation deadline under 20.2.50.123.B.(1) (rather than the 2-year deadline under 20.2.50.120 NMAC) to tanks used in hydrocarbon liquid transfers at gathering and boosting stations without controls. These changes are needed to eliminate costly measures that have no demonstrable ozone benefit and adjust implementation to reflect current supply chain challenges.

Pig Launching & Receiving, 20.2.50.121 NMAC, and Well Workovers, 20.2.50.124 NMAC. The record does not demonstrate that pig launching and receiving and well workover standards will contribute demonstrably to ensuring attainment or maintenance of the primary ozone standards. Their adoption is not supported by the record and would imperil the legal soundness of the rule. If the Board decides to proceed anyway, despite the negligible ozone benefit, then the requested redlines should be made to reduce the burden.

Pneumatic Controllers and Pumps, 20.2.50.122 NMAC. The Board should adopt NMED's proposed 20.2.50.122 NMAC (with minor revisions) because it requires reasonable but significant VOCs reductions from pneumatic controllers. NMOGA has proposed minor revisions, which the Department has reviewed and agreed with in concept, to improve implementation. These revisions clarify replacement requirements at existing facilities, clarify that compliance is set based on the tables, set forth a compliance methodology for determining compliance on January 1, 2024, 2027 and 2030, and provide greater certainty in handling controllers necessary for safety and process reasons. The revisions and their evidentiary basis are explained in this brief and the NMOGA redline. Board should reject proposals by other stakeholders to increase the stringency of pneumatics requirements because increasing stringency is unnecessary and, in many respects, impractical.

Storage Vessels, 20.2.50.123 NMAC. NMOGA generally supports the Department's proposal for controlling storage vessels under 20.2.50.123 NMAC, except that the 3 tpy applicability threshold for existing single tank batteries is not economically reasonable for the reasons set forth by Mr. Meyer at the hearing. After further discussion with NMED and review of the technical evidence, NMED has proposed a 4 tpy threshold for these tanks in its latest draft. While this is positive movement, the record demonstrates that a 6 tpy threshold for existing single tank batteries is supported by substantial evidence. Additionally, both NMOGA and the Department agree that the Board should defer immediate regulation of storage vessels at produced water management units from regulation under section 20.2.50.123 until the need for such controls is established under section 20.2.50.126 NMAC.

Produced Water Management Units, 20.2.50.126 NMAC. The Department has made significant improvements to the produced water management unit standards under 20.2.50.126

NMAC by eliminating arbitrary emissions limits and unproven requirements to apply covers that route vapors to air pollution control devices. With available technology, these standards would have required the oil and gas industry to reduce the size of recycling operations and, in some cases, resort to freshwater. The Department has responded to these concerns by imposing requirements that are achievable with current technology and preserve industry's ability to continue recycling activities. To further protect the industry's ability to recycle water, NMOGA urges the Board to either exclude recycling facilities from the definition of produced water management units or, at the very least, to clarify that the 50,000 barrel applies to all facilities as was implied throughout the hearing. This change will help ensure that the recycling activities critical to New Mexico's future can continue unimpeded.

NMOGA Final Redline. This brief does not address every argument for every change advocated by NMOGA. Additional argument and record support for requested changes are available in NMOGA's final annotated redline of 20.2.50 NMAC, submitted on January 20, 2022. NMOGA incorporates those statements here.

II. ARGUMENT

A. Stringency Relative to Federal Law. The Board Should Carefully Scrutinize All Sections of This Proposal That Are More Stringent than Federal Law and Reject Any Standard Where Public Notice Was Not Provided or Substantial Evidence of Greater Protectiveness Is Not in the Record.

The federal Clean Air Act requires the U.S. Environmental Protection Agency (EPA) to develop standards to combat air pollution, including standards for new sources of air pollution, 42 U.S.C. 7411, standards for sources of hazardous air pollutants, *Id*. 7412, and standards for the construction of new major sources and major modifications of existing major sources, among others. 42 U.S.C., Chapter 85, Subchapter I, Parts C and D. These standards represent minimum requirements for sources of air pollution throughout the country. States may adopt or enforce other emissions standards to control or abate air pollution that are more stringent than federal law, so long as state law authorizes such measures and the provisions are not impermissible for some other reason, such as federal preemption. 42 U.S.C. 7416.

The New Mexico Legislature has limited Board's authority to adopt standards that exceed the stringency of federal rules. Before adopting stricter standards, the Board must make a "determination, based on substantial evidence and after notice and public hearing, that the proposed rule will be *more protective* of public health and the environment." NMSA 1978, § 74-2-5.G (emphases added).

Section 74-2-5 does not simply require a finding that the proposed state standard requires something that the existing federal standard does not. If that were so, the standard would be self-fulfilling and meaningless because the conditions for applying the test—greater stringency—would be identical to the conditions for satisfying it. Instead, section 74-2-5.G requires the Board to find that the proposed standard will provide greater protection to public health and the environment in a way that is meaningful under the New Mexico Air Quality Act. In the context of a rulemaking aimed at reducing ozone concentrations, that means the standards should reduce ambient ozone concentrations and thereby improve the attainment and maintenance of the ozone NAAQS, which are designed to protect "public health and the environment." *See* § 74-2-5.G (requiring rule to be "more protective of public health and the environment"); 42 U.S.C. 7409(b) (requiring NAAQS to be protective of public health and welfare). There must be, at least, substantial evidence in the record to support the finding required by the statute. That said, the Board is not compelled to adopt a provision where there is substantial evidence to support the required finding. Instead, the Board has a duty to weigh competing evidence and to adopt or reject a particular proposal based on the weight of the evidence.

To implement these statutory directives, the Board must provide public notice that it intends to adopt standards more stringent than federal law, identify each substantive requirement of the proposal, compare that requirement against any federal counterpart, and evaluate the protectiveness of any standard that requires something that federal law does not. A standard should be rejected if the Board did not provide public notice that it intended to go beyond federal requirements or if the standard does not advance ozone attainment and maintenance in a way that is more protective than the standard's federal counterpart.

To honor the intent of the legislature, the Board must conduct this protectiveness evaluation individually for every proposal that exceeds the stringency of federal law. The Board cannot simply conclude that 20.2.50 NMAC as a whole is more protective than the existing patchwork of federal requirements applicable to oil and gas operators. This approach would render the statutory directive meaningless because it would allow the Board to adopt any number of ineffective standards so long as the rule package contained at least one measure that provided an iota of greater protection. The legislation supports that one measure; it cannot be argued it supports the others.

For this rule to survive scrutiny, the Board must correctly find that it provided public notice of its intent to adopt more stringent standards for affected sections and that the standards at issue provide greater protectiveness. As explained more fully throughout, the record does not support this finding for several aspects of the rule:[4]

[4] Note that this list is not exhaustive. For example, engines and turbines standards under 20.2.50.113 NMAC exceed the stringency of similar standards under 40 C.F.R. Part 60, Subparts GG, IIII, JJJJ and KKKK and 40 C.F.R. Part 63, Subparts ZZZZ and YYYY. However, NMOGA is not contesting these standards on this basis.

- Redundant VRU control requirements under 20.2.115.E(1)(b) NMAC, which have no federal counterpart.
- Leak detection and repair requirements, including the LDAR proximity proposal, under 20.2.50.116 NMAC, which either have no federal counterpart or exceed the stringency of similar requirements under 40 C.F.R. Parts 60, Subparts OOOO and OOOOa[5].
- Pig launching and receiving requirements under 20.2.50.121 NMAC, which have no federal counterpart.
- Storage vessel requirements under 20.2.50.123 NMAC, which exceed the stringency of similar requirements under 40 C.F.R. Parts 60, Subparts OOOO and OOOOa.
- Well workover requirements under 20.2.50.124 NMAC, which have no federal counterpart.
- Produced water management unit requirements under 20.2.50.126, which have no federal counterpart.

B. Economic Reasonableness. The Board Should Reject Proposals That Are Economically Unreasonable to Protect the Contributions the Oil and Gas Industry Makes to the New Mexico Economy.

The Board is required to give the weight it deems appropriate to the "economic reasonableness" of the proposed rule. NMSA 1978, § 74-2-5.G. While the Board has latitude in assigning the relative weight of the evidence relating to the factors it must consider under the Air

[5] NMOGA is aware that the federal EPA is currently working on updating New Source Performance Standards for many oil and gas operations covered by this rule. However, the Board's findings and conclusions must be based on the evidentiary record before it. As a nation-leading rule, the Board's actions here will help inform the EPA in assessing the limits of what's technically practicable and economically feasible.

Quality Control Act,, it must *consider* economic reasonableness to determine the weight that should be assigned, and it cannot altogether disregard economic impacts.[6]

John Dunham, technical witness for NMOGA, supplied the only comprehensive economic analysis of the rule. NMOGA Exhibit A6. NMED provided rebuttal testimony responding to Mr. Dunham's analysis (NMED Rebuttal Exhibit 19) but disclaimed any obligation to perform an analysis of their own. *See, e.g.,* Tr. 3:851:12-21.

Mr. Dunham testified that "the rule would cost oil and natural gas producers in the state a minimum of $3.8 billion 2020 dollars in direct administrative and operational costs over a 5-year period, with the bulk of these costs occurring in the first year or two." NMOGA Exhibit A6:2:13-15. Mr. Dunham estimated that this "could lead to a loss of as many as 3,217 jobs in the petroleum production industry in New Mexico and cost the state's economy $674.2 million annually. In addition, the state and its localities would receive almost $22.9 million less in tax revenue from businesses and employees in the oil and gas industry. This does not include reduced royalty and severance tax revenues resulting from lower production." Exhibit A6, "Estimated Costs of Proposed Ozone Precursor Rule on Oil and Natural Gas Development in New Mexico," at 1.

NMED witnesses Brian Palmer and Susan Day testified that Mr. Dunham's cost estimates were not well supported. NMED Rebuttal Exhibit 19. NMED estimated the costs of the rule to be $338 million per year, amounting to $1.7 billion in costs over 5 years. NMED Rebuttal Exhibit 19:2:19. NMED witnesses later revised this estimate to be $215 million per year or $1.1 billion in costs over 5 years. Tr., 3:795:5-10.

[6] Indeed, the U.S. Supreme Court has found that statutory language granting more discretion than what the Air Quality Control Act gives the Board "requires at least some attention to cost." *Michigan v. EPA*, 576 U.S. --- (construing language "necessary and appropriate" in air statute).

NMED's rebuttal and surrebuttal testimony about the costs of the rule was confusing and misleading. Unlike the $3.8 billion 5-year cost provided by Mr. Dunham, Mr. Palmer and Ms. Day's 5-year estimate of $1.1 billion did not include all costs for the life of the rule. Tr. 3:820:4-7. NMED witnesses testified that they estimated the costs of the rule would be incurred over 15 years instead of 5 years. Tr. 3:808:8-17. Based on NMED's estimated annualized costs of $215 million per year, the total costs of the rule over 15 years would be $3.2 billion. Tr. 3:832:13-16. Although NMED witnesses testified that they lacked sufficient information to evaluate Mr. Dunham's report and identified miscellaneous errors, NMED's $3.2 billion estimates for the total cost of the rule is consistent with Mr. Dunham's $3.8 billion estimate and confirms that the rule will have significant impacts on the New Mexico economy.

The Board should put significant weight on the undisputed macroeconomic impacts of this rule as it deliberates the economic reasonableness of individual provisions. As detailed below, various provisions of the rule impose unreasonable economic burdens relative to the air quality benefit anticipated and should not be adopted as proposed.

C. Scope, 20.2.50.2 NMAC. The Board Should Not Apply This Rule to Rio Arriba and Chaves County Because These Counties Do Not Have Department Monitors Demonstrating the Design Value Exceeds 95% of The Ozone Standard.

Section 74-2-5.C is clear that the Board's authority to adopt regulations is limited to those areas of the state exceeding 95 percent of the primary NAAQS: "Rules adopted pursuant to this subsection shall be limited to sources of emissions within the area of the state where the ozone concentrations exceed ninety-five percent of the primary national ambient air quality standard." NMSA 1978, § 74-2-5.C.

Rio Arriba County does not have a "design value" exceeding 95% of the NAAQS. The Department's witnesses conceded this point. Baca testimony, Tr. 1:301:17-21. The Department has now changed its position to argue that because some place in the air quality control region has a design value that exceeds 95%, the whole air quality control region and any county partially within it should have that design value. As the testimony elicited shows, that is not how design values work. Having chosen the "county" as a basis for its proposed rule, the Department must justify its proposal on that basis. The evidence shows that the only monitor in Rio Arriba County has a design value less than 95% of the ozone NAAQS and that concentrations are trending downward. There is no authority under the statute to impose proposed Part 50 on Rio Arriba County given the evidence before the Board that it does not exceed 95% of the ozone NAAQS. NMSA 1978, § 74-2-5.C.

Similarly, Chaves County has no design value and should not be included in Part 50. Tr. 1:191:12-18. The Department argued that it "contributes" to the ozone problem, but the "contribution" aspect of Section 74-2-5.C goes to the types of sources contributing to the ozone problem and does not authorize regulation of those sources unless they are in an area of the state exceeding 95% of the NAAQS. Section 74-2.5.C sets forth a two-step process before regulations may be adopted: In step 1, the Board "determines that emissions from sources … cause or contribute to ozone concentrations in excess of ninety-five percent" of the primary ozone NAAQS. In step 2, if this finding is made, then the "board … shall adopt a plan, including rules, to control emissions of oxides of nitrogen and volatile organic compounds to provide for attainment and maintenance" of the ozone NAAQS. But "rules adopted pursuant to this subsection *shall be limited to sources of emissions within the area of the state where the ozone concentrations exceed ninety-five percent*" of the ozone NAAQS. *Id.* Containing sources that "cause or contribute" is simply irrelevant to the question of whether Chaves County "exceeds" 95% of the NAAQS. For these reasons, the record does not support applying the rule to Chaves or Rio Arriba County.

D. Applicability, 20.2.50.111 NMAC. The Record Does Not Support NMED's Insistence that Only an Engineer Is Qualified to Calculate Potential to Emit.

The applicability of requirements under 20.2.50 NMAC turns largely on a source's potential to emit, which is "the maximum capacity of a stationary source to emit any air pollutant under its physical and operational design." 20.2.50.7.MM NMAC. NMED's current proposal prohibits air quality consultants who are not engineers from conducting this potential to emit analysis.

To justify this proposal, NMED testified that it wanted a certain level of assurance that the evaluation was accurate. *See* Kuehn testimony, Tr. 4:1157:17-4:1158:6; 4:1161:4-22. NMED admitted, however, that an engineer is not required for even complex permitting potential to emit calculations, which are frequently far more complex than the calculations required under proposed Part 50. Kuehn testimony, Tr. 4:1161:23-4:1162:4. Industry representatives testified that many professional engineers have no relevant expertise and that air quality consultants or compliance specialists, versed in how the air program determines potential to emit, were likely more qualified. See Marquez testimony, 5:1474:20-5:1475:25; Davis Testimony, Tr. 4:1183:4-19; 4:1184:4-20. (IPANM). Oxy noted that for its 645 facility and 2,745 wells, this engineer requirement could add nearly 6,780 engineering hours, at a cost of over $800,000. Holderman testimony, Tr. 4:1195:16-4:1196:7. For these reasons, the Board should allow qualified air quality consultants who are not engineers to conduct the PTE assessments required under Part 50.

This requirement would also be more stringent than federal law. PTE calculations for federal standards and permits are routinely done by non-engineering air quality consultants. As such, the Board cannot adopt these standards unless it finds they are more protective. It cannot make such a finding. The record demonstrates that NMED's engineering requirement creates unnecessary, hamstringing barriers around the air quality professionals who are often most qualified to conduct this work.

E. General Provisions, 20.2.50.112 NMAC. The Board Should Memorialize the Department's Commitment to Engage in a Stakeholder Process to Identify Date and Timestamp Technologies and Provide Industry Two Years to Integrate These Technologies.

Under various sections of Part 50, owners and operators must record a date and time stamp, including a GPS display of the location, of monitoring events. By January 1, 2023, the department has proposed to finalize and post a list of approved technologies to comply with date and time stamp requirements. Owners and operators would be required to comply with this requirement using an approved technology by April 1, 2023. Prior to this date, owners and operators are required to keep a written or electronic record of the date and time of any affected monitoring events.

The regulated community has significant concerns about this process and what will ultimately be required, ranging from uncertainty about whether the identified technologies will be compatible with existing systems to anxiety about establishing a robust, expensive system to perform one or fewer monitoring events per year. Importantly, the Department has committed to identify these technologies through a process that solicits and incorporates the feedback of stakeholders. Bisbey-Kuehn Testimony, Tr. 5:1358:24-25 - 1359:1-9. This stakeholder process is essential to ensuring that the identified technologies meet the stated goals without imposing undue burden on regulated entities. Despite the importance of the stakeholder process and the Department's commitment, 20.2.50.112.A(8)(b) NMAC simply states that the "department shall finalize a list of approved technologies" without any mention of soliciting or incorporating stakeholder input. We believe this is an oversight. NMOGA asks the Board to memorialize this commitment to engage with stakeholders in the statement of reasons and/or regulatory language to ensure that the identified technologies reflect the input of regulated entities.

In addition, the Board should grant industry at least two years to implement the approved technologies. After extensive testimony on this issue, Ms. Bisbey-Kuehn testified that the Department was amenable to extending the timeline consistent with industry's request. Bisbey Kuehn Testimony, Tr. 5:1582:14-17. The current Department proposal does not reflect that timeline, but we believe this is an oversight. As Ms. Kuehn and others testified, database development projects often take years. Kuehn testimony, Tr. 5:1370:3-8. The record indicates that technologies cannot be integrated into industry's database systems quickly and that additional time is needed. Smitherman testimony, Tr. 5:1427:21-5:1428:25; Brown testimony, Tr. 5:1437:19-5:1439:11. The Board should give industry at least two years to implement these technologies.

Beyond this remaining concern, the Department has made several crucial adjustments to 20.2.50.112 NMAC, and NMOGA urges the Board to adopt these revisions.

The Department has modified the requirement to comply with manufacturer specifications to allow owners and operators to rely on "an alternative set of specifications, maintenance practices and schedules sufficient to operate and maintain such sources in good working order, which have been approved by qualified maintenance personnel based on engineering principles and field experience." 20.2.50.112.A.1 NMAC; Kuehn testimony, Tr.

5:1356:6-16. This adjustment was made in response to voluminous testimony, which confirmed that reliance on alternative specifications provide needed flexibility without negatively impacting environmental outcomes. *See, e.g.,* NMOGA Exhibit A1, 15:13-25.

The Department has modified the annual reporting requirement under 20.2.50.112.D NMAC to address credible concerns prompted by prior iterations. Owners and operators would be required to annually generate a Compliance Database Report (CDR) on all assets under its control that are subject to the CDR requirements of Part 50 at the time the CDR is prepared and keep the report on file for five years. 20.2.50.112.D NMAC. Previously, the reporting language implied that an annual compliance certification requiring significant review, man hours and resources would be required, which various witnesses testified would be overly burdensome. Smitherman testimony, Tr. 5:1429:14-5:1430:14; Cooper testimony, Tr. 5:1492:7-5:1493:3. The department's most recent proposal is responsive to these credible concerns and provides an adequate metric of compliance assurance.

While Wild Earth Guardians and others testified that additional "deviation" reporting is necessary, these witnesses failed to demonstrate that the benefit of this reporting would outweigh the burden it would impose on both NMED and industry. Copeland testimony, Tr. 5:1456:24-5:1457:23. Wild Earth Guardians also did not address the Department's concerns that it could not accommodate substantial additional reporting. As Mr. Baca testified, this proposal would "overwhelm" the Department," "impose additional burdens that are without any public health benefits," and take the Department and industry away from the more important work of "addressing issues with compliance that have to do with emissions to the atmosphere." Tr. 5:1592:15; 1593:8-13.

F. Engines and Turbines, 20.2.50.113 NMAC. The Board Should Adopt the Department's Proposal Because It Requires Reasonable and Aggressive Emissions Reductions.

Industry stakeholders engaged extensively with the Department prior to and during the hearing to reach agreement on appropriate, aggressive standards that both existing and new engines and turbines could meet. The final result, encapsulated in the Department's September 16 and December 16 redlines, should not be disturbed. As Mr. Lisowski testified, there is no "blanket" technology that can meet all needs. Lisowski testimony, Tr. 6:1726:25-6:1727:7. Many of the low emitting combustor (LEC) controls are already implemented on existing turbines or else they may be small bore engines where these controls are not practical. Lisowski testimony, Tr. 6:1725:17-6:1727:7. Non-selective catalytic reduction (NSCR), used on many rich burn engines, is already in place and limited in further reduction by drift issues. Lisowski testimony, Tr. 6:1729:13-6:1730:8. Selective catalytic reduction (SCR) is not cost-effective or workable in the oil field as it is too expensive and requires full-time staffing, which is not available at most facilities. Lisowski testimony, Tr. 6:1730:9-6:1731:3. Based upon this testimony and supporting testimony from Mr. Dutton, Mr. Sheldon and Ms. Witherspoon, NMED, engine and turbine manufacturers, and industry reached an agreement on what is practical for New Mexico. Kuehn testimony, Tr. 6:1682:10-13. Mr. Lisowski also explained why the existence of the Alternative Compliance Plan did not mean that lower limits, such as the 1.2 g NOX/bhp-hr standard advocated by the environmental groups, could not feasibly be met. Lisowski testimony, Tr. 9:2993:13-18; 9:2999:25-9:3001:11. And Ms. Kuehn agreed that the original, more stringent, NMED proposal had not recognized the off ramps and exemptions found in the other regulatory programs or the differing field and gas conditions in New Mexico. Kuehn testimony, Tr. 6:1701:23-6:1702:5.

NMOGA also urges the Board to support the Department's decision to exclude relocations and like-kind exchanges from the definition of "construction." Kuehn testimony, Tr. 6:1686:1-6. This decision facilitates emissions reductions in the oil field by allowing engines to be "right sized" to the need, preventing them from running below optimal conditions (which would result in higher actual emissions), and allowing for more comprehensive maintenance in the shop as opposed to the field, which helps to keep the overall engine and turbine fleet in better repair. Initial concerns from the National Park Service that old turbines would be "dumped" on New Mexico were ameliorated once they understood that all existing units, including relocated ones, would be subject to the existing source emissions limits. Devore testimony, tr. 8:2401:2-8:2402:2. Similarly, the Board should support CO testing as a surrogate for VOC testing, because it is cheaper and will enable operators to tune their engines more efficiently. Lisowski testimony, tr. 6:1734:2-8.

The National Park Service in its pre-filed testimony requested that emissions limits be established for smaller engines. Multiple experts testified that the proposed limits were not achievable in a cost-effective manner and urged that they not be adopted. *See* Trent, Tr. 6:1814:9-16; Sheldon and Dutton, Tr. 6:1757:1-6:1760:13, Lisowski Tr. 9:2990:20-9:2991:20. Based on this testimony, the National Park Service withdrew its request to regulate the smaller engines. Devore testimony, Tr. 8:2399:24-8:2400:9.

The Department's initial proposal applied 20.2.50.113 NMAC to portable engines, which include nonroad engines. NMED has since revised its proposal so that proposed 20.2.50.113 NMAC does not apply to nonroad engines. The Board should follow the Department's course in excluding nonroad engines from the rule because emissions standards for such engines are subject to exclusive federal control. 42 U.S.C. § 7543(e); *Engine Mfrs. Ass'n v. U.S. E.P.A.*, 88

F.3d 1075, 1087-88 (D.C. Cir. 1996) (“states must be preempted from adopting any regulation for which California could receive authorization.”); *Pac. Merch. Shipping Ass'n v. Goldstene*, 517 F.3d 1108, 1113 (9th Cir. 2008) (“we join the D.C. Circuit and hold that the implied preemption of § 209(e)(2) applies to ‘any nonroad vehicles or engines,’ including new and non-new sources.”).

G. Control Devices, 20.2.50.115 NMAC. The Board Should Adopt the Department’s Control Devices Standard, Except that The Redundant VRU Requirement Is Not Supported By the Record and Should be Rejected.

Under proposed 20.2.50.115.E(1)(b), owners and operators must “control VOC emissions during startup, shutdown, maintenance, or other VRU downtime with a backup control device (e.g. flare, ECD, TO) or redundant VRU during the period of VRU downtime.” To the best of NMOGA’s understanding, the Department has not estimated the costs or emissions reductions associated with a redundant control device. Because these control devices are required to be used only during “startup, shutdown, maintenance, or other VRU downtime” and such events are inherently infrequent, the emissions reductions to be gained from redundant controls are slight, while the cost of acquiring, installing, and maintaining these redundant controls are relatively similar to the costs associated with acquiring, installing, and maintaining the primary control device. Consequently, the cost-per-ton reduced of the redundant control requirement is excessive.

The redundant control requirement also has no federal corollary. As such, the Board must find that these requirements are more protective than federal law to support their adoption. There is no evidence in the record to suggest that the minimal emissions reductions associated with redundant controls would have a demonstrable impact on ozone concentrations. For this reason, the Board should not adopt these standards.

If the Board determines against the weight of evidence to adopt these standards, NMOGA urges the Board to not require redundant controls during a facility-wide upset. The reason for this is simple: the conditions that caused the primary VRU to be down will also impact any redundant controls. To ensure this standard is technically feasible, it should not apply during such events.

Beyond this concern, the Department and other stakeholders have worked throughout this rulemaking to clarify and refine section 20.2.50.115 NMAC in several ways, as documented in NMED and NMOGA's final redline. NMOGA asks that the Board adopt these critical changes.

H. Equipment Leaks & Fugitive Emissions, 20.2.50.116 NMAC.

i. **The Board Should Reject the More Stringent Leak Detection and Repair Thresholds and Frequencies Proposed by NMED and Adopt NMOGA's Proposal Because the Added Stringency of NMED's Proposal Has Minimal Impacts on VOC Reductions and Fails to Account for The Diminishing Returns of Increased Survey Frequency.**

The record reflects that VOC emissions reductions are not very effective at reducing ozone in New Mexico. The Board must give due consideration to the "character and degree of injury to or interference with health, welfare, visibility and property." NMSA 1978, § 74-2-5. This means the Board must consider the harm at issue and develop rules that are responsive to that harm. By requiring the Board to consider character and degree of injury, the legislature seeks to establish a fit between the problem and solution. For example, if the character of injury is such that only certain types of measures will redress that injury, the statute implicitly directs the Board to only adopt those standards that are responsive.

While New Mexico needs strong measures to address ozone, the weight of evidence fails to support the proposition that reducing VOC emissions through measures such as LDAR will redress that injury. The areas of New Mexico impacted by this rule are NOx sensitive, meaning that VOC emissions reductions have a relatively lesser impact on ozone concentrations, particularly in the quantities attributable to anthropogenic sources, such as oil and gas. As Mr. McNally testified, "additional controls on oil and gas VOC emissions are not an effective means of controlling ambient ozone levels in New Mexico, except for possibly in a very limited area in northeastern San Juan County." NMOGA Exhibit A4, at 16. Based on the limited efficacy of VOC controls, it makes little sense to adopt some of the most stringent statewide leak detection and repair standards in the country when those standards will do little to help the state combat its ozone challenges.

While NMOGA supports a strong LDAR program as a matter of good policy, NMOGA does not believe the onerous proposals advanced by the Department are warranted given the limited impact VOC emissions reductions are anticipated to have on ozone concentrations. Adopting these proposals would reflect inadequate consideration of the "degree and character" of the injury and the ability of these standards to redress that injury.

In addition to considering the character and degree of injury, the Board also must consider the "technical practicability and economic reasonableness of reducing or eliminating air contaminants from the sources involved." NMSA 1978, § 74-2-5. This mandatory consideration reflects the legislature's assessment that not all possible emissions reductions are worth pursuing: where there are technical or economic challenges that outweigh the benefits of implementing the proposed standards, based on the weight of evidence, such standards should not be adopted.

Based on this consideration, the Board should reject the excessive leak frequencies proposed by the department because they impose unreasonable costs on the oil and gas industry and provide little emissions benefit. The competing proposals are as follows:

	Well Sites & Standalone Tank Batteries		**Gathering and Boosting Stations, Gas Plants, and Transmission Compressor Stations**	
Frequency	**NMED**	**NMOGA**	**NMED**	**NMOGA**
Annually	<2 TPY	<10 TPY	None	None
Semiannually	=>2 to <5 TPY	=>10 to <25 TPY	None	<25 TPY
Quarterly	=>5 TPY or more	=>25 TPY or more	<25 TPY	=>25 TPY
Monthly	None	None	=>25 TPY	None

As is clear from these proposals, although NMOGA is not aligned with the department, NMOGA has nevertheless proposed an aggressive leak detection program. NMOGA's proposal ultimately strikes a more appropriate balance.

Mr. Smitherman's testimony makes clear that most leaks are identified and repaired during initial surveys. NMED's own data demonstrates that 40% of all emissions reductions from LDAR are achieved with annual surveys, 60% are achieved with semiannual surveys, and 80% are achieved with quarterly surveys. *See* NMOGA Exhibit 58, at 14. A study from the American Petroleum Institute consisting of 6,000 surveys across 3,482 sites also found less than 2 leaks per site during initial surveys, with the leak rate falling quickly to less than 1 leaking component on average in subsequent surveys.

Although the quantity of leaks detected diminish with increased frequency, the per-survey cost of conducting LDAR remains relatively the same, meaning that less emissions per dollar are reduced with each additional survey. NMOGA's technical testimony demonstrates the

Incremental cost per ton of VOC reduction - ERG Costs & NMOGA Reductions			
Annual to Quarterly	**Incremental VOC Reductions (tpy)**	**Incremental Annual Cost (2019)**	**Incremental Cost per Ton**
NG Well Site	0.509	$3,016	$5,923
Oil Well Site (GOR < 300)	0.096	$3,016	$31,553
Oil Well Site (GOR >= 300)	0.122	$3,016	$24,681

Incremental cost per ton of VOC reduction - ERG Costs & NMOGA Reductions			
Annual to Semiannual	**Incremental VOC Reductions (tpy)**	**Incremental Annual Cost (2019)**	**Incremental Cost per Ton**
NG Well Site	0.255	$ 1,005	$3,947
Oil Well Site (GOR < 300)	0.048	$ 1,005	$21,028
Oil Well Site (GOR > 300)	0.061	$ 1,005	$16,448

Incremental cost per ton of VOC reduction - ERG Costs & NMOGA Reductions			
Semiannual to Quarterly	**Incremental VOC Reductions (tpy)**	**Incremental Annual Cost (2019)**	**Incremental Cost per Ton**
NG Well Site	0.255	$ 2,011	$7,899
Oil Well Site (GOR < 300)	0.048	$ 2,011	$42,078
Oil Well Site (GOR > 300)	0.061	$ 2,011	$32,913

The following table illustrates the incremental costs of increased LDAR monitoring at gathering and boosting sites (NMOGA Exhibit 58, at 50):

Incremental Cost per Ton of VOC Reduction			
	ERG Costs & Reductions	NMOGA Costs & Reductions	
	New Mexico	San Juan	Permian
Annual to Semiannual	$3,068	$17,154	$6,905.55
Semiannual to Quarterly	$6,136	$34,313	$13,813.14
Annual to Monthly	$9,586	$80,303	$32,326.67
Semiannual to Monthly	$13,940	$122,402	$49,274.08
Quarterly to Monthly	$29,627	$298,580	$120,195.96

As this analysis demonstrates, increasing LDAR frequency achieves minimal emissions reductions relative to the costs incurred. For well sites, NMOGA's analysis uses NMED's own data, except that NMOGA has used a different model plant. As discussed in Mr. Smitherman's testimony, a model plant is a statistically average facility commonly used in rulemaking efforts to quantify costs and emissions reductions associated with a proposal. In the leak detection context, the goal of a model plant is to estimate the average population of potentially leaking components at a given facility type. Roughly speaking, constructing a model plant involves gathering data on the number of potentially leaking equipment and components at facilities to derive an average component count. An emissions estimate is then derived by multiplying the component count by the leaking component emissions factor.

While NMED relied on well site model plant data from 1996 based on equipment surveys conducted outside of New Mexico, NMOGA relied on a model plant derived from data gathered from New Mexico oil and gas operators in 2019. NMOGA's more recent and geographically relevant data came from EPA's 2019 GHG report and showed that, on average, New Mexico sites have fewer pieces of equipment per site, fewer components per piece of equipment, and lower potential leak emissions than was observed in the 1996 study NMED has relied upon. Unlike adjustments to the well site model plant, NMOGA's incremental analysis for well sites does not alter the cost data NMED relied upon, even though there is ample evidence in the record to suggest that NMED has underestimated such costs. Similarly, while NMED relied on gathering and boosting station model plant data derived from a 1995 EPA/GRI study, NMOGA relied on a 2019 Colorado State University study, which showed fewer equipment, fewer components, and lower potential leak emissions relative to NMED's data. NMOGA Exhibit 28.

As the Board may recall, several parties fought hard to keep NMOGA's incremental LDAR analysis from being admitted into evidence. Nevertheless, since the incremental LDAR analysis has been admitted, its substantive conclusions have largely gone unrefuted. On rebuttal, NMED argued it could not evaluate the model plants because it did not understand how they were constructed. On surrebuttal, NMOGA countered that it provided the model plant data, and NMOGA applied the same methodology to construct its model plant that EPA applied in constructing the model plant upon which NMED relied. On surrebuttal, Mr. Palmer testified that the CTG does not direct states to conduct an incremental cost analysis, implying that such a review is not appropriate. Tr. 8:2778:18-20. But Mr. Palmer does not take issue with the methodology or mathematical conclusions reached by Mr. Smitherman. And the fact that the CTG does not recommend an incremental cost analysis is of no consequence. The CTG is guidance and has no bearing on the factors the Board must consider in fulfilling its statutory duty under state law. The Board is obligated to consider the "economic reasonableness" of the proposals put before it. NMOGA's uncontroverted incremental analysis establishes that the Department's LDAR proposal is not economically reasonable and should not be adopted.

This does not mean that NMOGA believes that no LDAR requirements should be adopted. Instead, NMOGA believes that the frequencies and thresholds it has provided in its comments represent a more reasonable way of attaining VOC reductions at a less exorbitant cost.

ii. The Board Should Reject the Proximity LDAR Proposal Because It Is Beyond the Scope of This Rulemaking, Does Not Demonstrably Contribute to The Objective of Attaining and Maintaining the Primary Ozone Standard, and is Not Cost-Effective.

Ensuring attainment and maintenance of the ozone standards is the statutorily prescribed objective of this rulemaking.[7] Per the statute, the rule ultimately adopted by the Board seeks to "provide for attainment and maintenance of the primary ozone NAAQS" set by EPA in areas of the state "where the ozone concentrations exceed ninety-five percent" of the standard. NMSA 1978, § 74-2-5.C. The Board lacks authority to adopt any Department or stakeholder proposals that do not demonstrably contribute to this attainment and maintenance goal.

This limitation is imposed by the statute itself. Under NMSA 1978, § 74-2-5.C, the Board is authorized to adopt a plan, including rules, to control emissions of oxides of nitrogen and volatile organic compounds. However, this authority is limited those measures necessary "to provide for attainment and maintenance of the standard." *Id.* Consequently, proposals that call for control of air toxics, for example, in ways that have nothing to do with mitigating ozone are not within the Board's authority in this rulemaking. While the Board may adopt standards that have co-benefits, such as NOx emissions limits for engines that also reduce hazardous air pollutant emissions, a proposal must provide a demonstrable benefit towards attaining or maintaining the primary ozone standard. If a proposal does not, it is not made "to provide for attainment and maintenance of the standard," and it is beyond the scope of Board's authority under NMSA 1978, § 74-2-5.C. Put simply, the Board does not have authority to adopt standards

[7] Congress enacted the Clean Air Act ("CAA") in 1970 to address a variety of air pollution problems. A central piece of this legislation was the directive that the Environmental Protection Agency ("EPA") promulgate primary and secondary national ambient air quality standards ("NAAQS") for six criteria pollutants: PM_{10} and $PM_{2.5}$, SO_2, NO_2, CO, lead and ozone. 42 U.S.C. 7409(a).

that only provide or primarily provide a benefit tangential to the primary target of the regulation, and allowing adoption of such rules would remove all effective limits on rulemaking authority. Ms. Paranhos, representing EDF, conceded as much. Tr. 8:1245:20-8:1246:2.

The Board is also limited to adopting rules that provide for the attainment and maintenance of the ozone standard because that is what Board's public notice stated. Pursuant to NMSA 1978, § 10-15-1, the Board must provide public notice announcing its intention to consider a petition by the Department to adopt rules addressing ozone. "Compliance with prescribed notice requirements is a prerequisite to any valid action by [the Board], and failure to give proper notice constitutes a jurisdictional defect rendering action of [the Board] null and void." N.M. Att'y Gen. Op. No. 90-29 (Dec. 20, 1990). The public notice provided:

> The purpose of the public hearing is for the Board to consider and take possible action on a petition by the New Mexico Environment Department ("NMED") requesting the Board to adopt a plan, including proposed new regulations at 20.2.50 NMAC. The requested action is currently authorized pursuant to the New Mexico Air Quality Control Act, NMSA 1978, Section 74-2-5.3, which requires that the Board adopt a plan, including regulations, <u>to ensure attainment and maintenance of the National Ambient Air Quality Standard ("NAAQS") for ozone within areas of the State that have monitored ozone concentrations that exceed 95% of the NAAQS</u>.

See NMED Exhibit 112 (emphases added). As the public notice makes clear, the purpose of this rulemaking is narrow—to reduce emissions of ozone precursor pollutants "*to ensure attainment and maintenance*" of the standard. While the Board has authority to otherwise undertake a rulemaking to reduce pollutants that have no bearing on NAAQS, such as regulation of hazardous air pollutants, such an undertaking is not described in the public notice and is not authorized under NMSA 1978, § 74-2-5.C.

Clean Air Advocates, EDF, and others have urged the Board to require leak detection monitoring at well sites within 1,000 feet of an occupied area on a quarterly basis where sites have a PTE less than 5 tpy VOC and monthly where sites have a PTE equal to or greater than 5 tpy VOC. *See* CAA, Exhibit 22, at 17. After extensive testimony on this issue, the Department signaled its support. Mr. Smitherman, on behalf of NMOGA, also testified that NMOGA would support weekly AVOs and quarterly Method 21 or OGI, as opposed to the monthly inspections. Other industry stakeholders did not endorse more frequent LDAR for well sites near occupied areas.

While this proposal has been endorsed by the NMED and others, after fuller consideration of the evidence adduced in support of the proposal and consideration of NMSA 1978, § 74-2-5, NMOGA respectfully disagrees that the Board has authority to adopt such a rule given the evidentiary record before it. Increasing LDAR within one-thousand feet of an occupied area has no relationship to reducing ozone concentrations for those targeted locales. Instead, as Ms. Lee Ann Hill, witness for Clean Air Advocates testified, the concern driving the LDAR proximity proposal is the direct emissions of VOCs and hazardous air pollutants, not the secondary ozone that may form as the results of these direct emissions. *See* Tr. 9:2847:21-25 – 2849:1-6. When questioned about whether ozone would form within 1,000 feet of the wellhead, Ms. Hill testified that she had "not personally evaluated ozone formation given particular distances from oil and gas sites." *See* Vol. 9, 2848:15-21. Other witnesses questioned on this point failed to provide any testimony, let alone evidence, that ozone formation within 1,000 feet of a well site is occurring or will be prevented by the implementation of this standard in a way that will ensure attainment and maintenance of the primary standard. *See, e.g.,* Vol. 8, 2730:4-25 – 2735:1-11. As CDG witness, Ms. Lori Marquez testified, "ozone is a regional pollutant," and "technical work performed by EPA demonstrates that individual minor sources in New Mexico [such as well head sites subject to the proximity proposal] do not cause or contribute to ozone NAAQS violations." Testimony of

Lori Marquez, Tr. 5:1476:15-19. The purpose of this rulemaking is to ensure attainment and maintenance on a large scale—in counties and groups of counties.

Because the LDAR proximity proposal has no federal corollary, it is more stringent than federal requirements and triggers the heightened substantial evidence standard in NMSA 1978, § 74-2-5.G. Given that the record contains no evidence that secondary ozone is forming within 1,000 feet of a wellhead, the Board has no evidence upon which to conclude the standard is more protective of the primary benefits targeted by this rulemaking—ozone reductions. Although the record contains evidence that the LDAR proximity proposal may be more protective in a general sense, that is not sufficient to satisfy the statutory standard for this rulemaking. The statutory authority for this rulemaking and the public notice provided do not contemplate regulation of direct emissions for purposes unrelated to ozone formation. Adopting such standards on this basis as part of this rulemaking would deprive the public of fair notice and exceed the operative statutory authority.

If the Board determines against this weight of evidence that it has authority and has provided sufficient notice, the Board should not adopt any standard more stringent than NMOGA's good faith offer to conduct weekly audio, visual, olfactory ("AVO") inspections and quarterly Method 21 or OGI monitoring within 1,000 feet of an occupied area..[8] As Mr. Smitherman testified, increasing LDAR frequency yields diminishing returns. As Member Honker noted, most of the emissions reductions from LDAR come from the first few cycles of conducting the survey. Although emissions available for reduction decrease the more frequently surveys are conducted, the primary cost driver of conducting LDAR—the survey itself—remains

[8] The Board should also adopt the limiting clarification NMOGA has proposed to the definition of "Occupied area." The last clause, (4), broadly refers to outdoor venues and recreation areas. Recreation area can be broadly construed to cover National Forests and similar dispersed recreation areas, which would broaden the "proximity LDAR" proposal beyond recognition. See suggested revisions in NMOGA redline, 20.2.50.7 NMAC.

the same. As such, the more frequently LDAR is conducted, the less frequently leaks are identified, the less emissions there are to prevent, and the less cost-effective the entire exercise becomes. This fact becomes especially apparent when reviewing the incremental cost-effectiveness of conducting LDAR. Consider the cost effectiveness of moving from semiannual to quarterly LDAR surveys:

Incremental cost per ton of VOC reduction - ERG Costs & NMOGA Reductions			
Semiannual to Quarterly	**Incremental VOC Reductions (tpy)**	**Incremental Annual Cost (2019)**	**Incremental Cost per Ton**
NG Well Site	0.255	$ 2,011	$7,899
Oil Well Site (GOR < 300)	0.048	$ 2,011	$42,078
Oil Well Site (GOR > 300)	0.061	$ 2,011	$32,913

NMOGA Exhibit 58, at 48.

While the costs are excessive for natural gas well sites, they are astronomical for oil well sites. Mr. Smitherman conducted additional analysis on the costs of transitioning from quarterly to monthly LDAR consistent with the LDAR proximity proposal, but this is analysis is contained in the proffered materials for which Board has yet to issue a ruling. But the Board can draw its own conclusions from the evidence already in the record: if transitioning from twice a year to four times a year is not cost-effective, transitioning from four times a year to twelve times a year is also not cost-effective.

Because the rationale for increasing LDAR near well sites is not targeted at the ozone problem, the Board lacks authority to adopt this proposal as part of this rulemaking. While the Board may have authority to adopt such a proposal in a properly noticed public hearing addressing this issue, that is not the case here, where the statutory basis and public notice only contemplate measures to address ozone.

I. Hydrocarbon Liquid Transfers, 20.2.50.120 NMAC. The Board Should Adopt the Department's Latest Redline with Minor Revisions Because the Proposal Incorporates Several Changes Consistent with the Board's Obligation to Consider the "Technical Practicability and Economic Reasonableness" of Its Rules.

Prior versions of proposed 20.2.50.120 NMAC applied to production facilities and associated tank batteries delivering liquids directly to pipelines and produced water transfers. Mr. Smitherman credibly testified that regulating such sources presents technical challenges, would not be cost-effective, and would not result in significant emissions reductions. NMOGA Exhibit A1, 26:1-46 – 27:1-12. The Department's latest proposal adjusts the rule to address this testimony, and NMOGA urges the Board to concur with these conclusions.

The Department's latest proposal exempts facilities from section 20.2.50.120 NMAC that perform less than 13 loadouts per year. 20.2.50.120.A NMAC. This exemption is based on the testimony of Mr. Smitherman, who testified that hydrocarbon liquid transfers are a function of event frequency, that sites that perform liquid transfer infrequently have a low emitting potential, and that the required controls are not warranted on a cost-per-ton basis for low-emitting operations. NMOGA Exhibit A1, 27:15-26. NMOGA urges the Board to find these changes are supported by the record.

The Department's current proposal requires industry to visually inspect hydrocarbon liquid transfer equipment monthly at staffed locations and semiannually at unstaffed locations. 20.2.50.120.C.1 NMAC. These requirements reflect the testimony of Mr. Smitherman who testified to the logistical challenges and administrative burden of conducting inspections more frequently, particularly when sites are unmanned or remotely located. NMOGA Exhibit A1, 28:37-46. The monthly and semiannual inspection frequencies reflect a reasonable strategy for evaluating compliance with hydrocarbon liquid transfer requirements, and NMOGA urges the Board to concur.

The Department's latest proposal also requires hydrocarbon liquid transfers to be controlled within 2 years of the effective date. For sources that control transfers by routing vapors to a storage vessel, this effectively supersedes the multiyear phase-in schedule proposed under 20.2.50.123.B.(1) NMAC for storage vessels. Unlike the 2-year deadline under 20.2.50.120 NMAC, section 123 requires that 30% of existing storage vessels be controlled by January 1, 2025, 35% by January 1, 2027, and the remainder by January 1, 2029. *See* 20.2.50.123.B.1(a)-(c) NMAC. Some gathering and boosting sites route vapors back to existing tanks without existing controls during transfer events and do so on a large scale. These operators cannot practically retrofit their entire inventory of storage vessels with combustion controls within two years for the same reason that owners and operators of storage vessels generally need a phase-in period under 20.2.50.123.B.(1) NMAC. As Mr. Holderman testified, steel shortages, component shortages, labor shortages, limited manufacturing capacity, and other supply chain issues make meeting these demands within 2 years infeasible. Tr. 9:2899:4-25 - 9:2900:1-9. The Board should direct that hydrocarbon liquid transfers at existing gathering and boosting stations (including associated tank batteries) without any controlled storage vessels are subject to the requirements of 20.2.50.120 NMAC on the schedule in 20.2.50.123.B.(1) NMAC.

Finally, under the Department's May 6, 2021 proposal, oil and gas owners and operators were required to conduct vapor tightness testing on tanker trucks or tanker rail cars used for hydrocarbon liquid transfers. In the July 28, 2021, proposal, the Department removed these provisions. In its direct testimony, the Department explained the reason for this change: "Tanker trucks and tanker rail cars transporting hydrocarbon liquids are not subject to Part 50 and were not analyzed by the Department during the development of the requirements in Part 50. The Department did not intend to impose testing and inspection requirements on equipment not subject to Part 50." NMED Direct Exhibit 32, at 11. NMOGA agrees with the removal of these standards. Under 49 U.S.C. § 5125(b), the vapor tightness standards are preempted because they would have imposed more stringent testing requirements on hazardous material containers than federal hazardous material transportation law. Similarly, under 49 U.S.C. § 10501(b), the standards are federally preempted as they relate to rail shipments because they would have had the effect of managing or governing rail transportation, an area of regulation reserved to the federal government.

J. Pig Launching & Receiving, 20.2.50.121 NMAC, and Well Workovers 20.2.50.124 NMAC. The Board Should Reject Standards for Pig Launching & Receiving and Well Workovers Because They Do Not Demonstrably Impact Ozone.

To evaluate the impacts of the proposed rule on ozone, NMED commissioned a photochemical model. The purpose of the model was to assess the impacts of proposed Part 50 controls on ozone concentrations in New Mexico. The testimony of NMOGA witness Dennis McNally characterized the model results as follows:

> The ozone air quality benefits of the proposed rule are quite modest, and what impacts the rule does have are primarily the result of the NOx control measures. Additional controls on oil and gas VOC emissions are not an effective means of controlling ambient ozone levels in New Mexico, except for possibly in a very limited area in northeastern San Juan County.

NMOGA Exhibit A4, at 16. NMED's expert Ralph Morris, who conducted the analysis on behalf of NMED, concedes this point. *See, e.g.,* Tr. 2:397:1-20.

To provide context on a per-ton basis, Mr. Morris testified that an increase or decrease of 670 tons of NOx emissions per year one way or another would have "no material effect on ozone results." Vol. 2, 381:1-12; 398:9-14. Mr. McNally similarly testified that increases or decreases in VOC emissions in excess of a thousand tons of VOC per year would have no demonstrable impacts on ozone concentrations. Vol. 2, 494:22-25 – 495:1-5.

According to NMED's own witnesses, standards under 20.2.50.121 NMAC for pig launching and receiving and standards under 20.2.50.124 NMAC for workovers will not reduce emissions in amounts exceeding these thresholds. As such, if these standards are not adopted and the anticipated reductions are added back to the inventory, the increase will not have an impact on ozone attainment or maintenance.

Ms. Bisbey-Kuehn testified that NMED estimates overall emissions reductions of 22.9 tons of allowable VOC emissions from implementation of the proposed standards for pig launching and receiving under 20.2.50.121 NMAC. Tr. 9:3053:5-11. Ms. Bisbey-Kuehn testified this number did not account for all emissions because the Department's emissions inventory is not complete. *Id.* But even if the emissions were underestimated by a factor of 45, they would not move the ozone needle according to the testimony of Mr. McNally and Mr. Morris. Moreover, because the Department's pig launching and receiving standards have no federal counterpart, these standards are more stringent than existing federal law. As such, they trigger the protectiveness evaluation in NMSA 1978, § 74-2-5.G. A statement that the requisite information to justify the rule is not available does not qualify as "substantial evidence" of greater protectiveness. The Board should reject this proposal as it provides no demonstrable benefit to ozone attainment and maintenance.

Similarly, NMED provided no emissions estimates to support the implementation of best management practices for well workovers under proposed 20.2.50.124 NMAC. According to

NMED witness, Mr. Palmer, "emissions estimates for workover operations are not currently available in the modeling emissions inventory or found in the NMED equipment data." Vol. 9, 3101:19-23. The workover proposal has no federal counterpart and is thus subject to the heightened protectiveness evaluation in NMSA 1978, § 74-2-5.G. Because the record contains no evidence that VOC emissions from workovers have any impact on ozone, the NMED has not provided substantial evidence to support adoption of the standard.[9]

If the Board ultimately adopts these standards against the weight of the evidence cited above, NMOGA urges the Board to also adopt the modifications advocated for by NMOGA, which are contained in its latest redline and include accompanying record support.

K. Pneumatic Controllers and Pumps, 20.2.50.122 NMAC. The Board Should Adopt NMED's Pneumatics Proposal, with Minor Changes to Enhance Workability, and Reject Proposals by Other Stakeholders to Increase the Stringency of Pneumatics Requirements.

NMED's proposal requires all new natural gas-driven pneumatic controllers to have an emission rate of zero and a specified percentage of existing controllers to be non-emitting according to the schedule in proposed 20.2.50.122.B(3) NMAC. The proposal ultimately requires anywhere from 80 to 90% of controllers at well sites, tank batteries, and gathering and boosting stations to be non-emitting by January 1, 2030, and 98% of pneumatic controllers at transmission compressor stations and gas processing plants to be non-emitting by January 1, 2030. The proposal also requires new pneumatic diaphragm pumps located at natural gas processing plants to be non-emitting; new pneumatic diaphragm pumps located at well sites, tank batteries, gathering and boosting stations, or transmission compressor stations with access to commercial line electrical power to be non-emitting; existing pneumatic diaphragm pumps located at well sites, tank

[9] If the Board determines to retain these provisions even in the absence of record evidence, the changes proposed by NMOGA should be incorporated to reduce the burden in light of the negligible emissions benefit.

batteries, gathering and boosting stations, natural gas processing plants, or transmission compressor stations with access to commercial line electrical power to be non-emitting within two years; and certain pneumatic diaphragm pumps to be controlled by 95% where non-emitting technology is unavailable.

Other stakeholders object to the Department's pneumatic controller proposal primarily because it is different than Colorado's approach. While Colorado requires phaseout of pneumatic controllers on a production basis, New Mexico has applied a phaseout based on controller count. As Ms. Bisbey-Kuehn and Mr. Palmer explained, Colorado's approach is not appropriate for New Mexico. *See generally,* Tr. 7:2025:20-25 - 2027:1-15. Colorado has been regulating pneumatic controllers since 2009, and it has extensive infrastructure and administrative resources in place necessary to administer a program like Colorado's. Palmer Testimony, Tr. 7:2022:19-23; Bisbey-Kuehn Testimony, Tr. 7:2026:12-22. This is not the situation New Mexico finds itself in, as the state is regulating pneumatic controllers for the first time through proposed Part 50. Bisbey-Kuehn testimony, Tr. 7:2027:4-9. Unlike Colorado, New Mexico does not have the benefit of building the pneumatics program on top of emissions reductions already achieved by past regulatory efforts. Tr. 7:2022:19-23. The current proposal recognizes the status of the industry in New Mexico while requiring leaps forward to achieve significant emissions reductions. To the extent other stakeholders have espoused a production-based approach, it should be rejected for these reasons. Bisbey-Kuehn testimony, Tr.7:2028:4-13; Smitherman testimony, Tr. 7:2109:5-18.

In addition to requesting a production-based approach, other stakeholders propose measures to increase the stringency of the proposal. These measures would require owners and operators to achieve a fixed increase in the percentage of non-emitting controllers rather than attain a fixed point, require gas driven controllers at gas processing plants or transmission compressor stations to be converted to non-emitting within six months, accelerate the timeline so that all retrofits occur by 2025 rather than 2030, and remove the early action incentive in NMED's proposal. The rationale provided for these changes boils down to Colorado took a similar approach, so New Mexico should too. For the reasons outlined above, New Mexico is not Colorado, and the approach taken by another jurisdiction with different challenges and opportunities has little bearing on what's right for New Mexico. These requirements are often not technically or economically feasible and place strains on both the companies and supply chains. Smitherman testimony, Tr. 7:2109:14-7:2110:4. In addition, the only concrete evidence offered by Dr. McCabe for the six-month proposal was that natural gas processing plants were able to achieve this within 6 months in Colorado. McCabe testimony, Tr. 7:2076:14-17; Smitherman testimony, Tr. 7:2108:11-23.. But as Dr. McCabe conceded and other witnesses noted, natural gas processing plants are large facilities with electric power that are relatively few in number and were not caught up in the pandemic's supply chain snarls. McCabe testimony, Tr. 7:2076:14-17. There is no compelling evidence in the record that a faster transition is possible and a lot of testimony why it is not given New Mexico's starting point and pandemic impacts.

Requiring retrofit at gas processing plants and transmission compressor stations within six months is also infeasible and unnecessary. Multiple witnesses with direct experience designing systems, planning retrofits, and grappling with current supply chain issues testified that this proposal is unrealistic. *See, e.g.,* Tr. 7:2108:11-23; 2214:14-18; 2283:1-8; 2284:9 – 2285:25. Requiring phaseout to be completed by 2025 similarly presents logistical challenges. More importantly, as Mr. McNally testified, "The earlier imposition of VOC controls would have little impact on ozone levels in NM." NMOGA Exhibit 45, at 8.

Finally, these proposals should be rejected because NMED is requiring owners and operators to apply leak detection and repair measures to pneumatic controllers and pumps, a measure that significantly reduces the urgency of phaseout. NMED Rebuttal Exhibit 23, 20.2.50.116.C NMAC. Multiple witnesses testified that there are "significant emissions from malfunctioning gas-powered pneumatic controllers" and that applying LDAR to these devices would reduce emissions from these malfunction events. *See, e.g.,* Tr. 7:60:6-9; 7:2224:8-24. If these malfunctioning devices are being identified and repaired, then New Mexico has less to gain by hastening their replacement. Tr. 7:2275:4-14. Because NMED's original pneumatics proposal did not contemplate imposing LDAR on pneumatic controllers, its cost-per-ton analysis did not consider emissions reductions attributable to LDAR. *See* NMED Exhibit 95. Consequently, when NMED adopted the pneumatic LDAR proposal, it should have updated its cost-per-ton analysis to include consideration of the LDAR costs and tons reduced before calculating the phase out costs and tons reduced, which would be less. Eliminating this error significantly decreases the cost-effectiveness of the retrofit requirements and counsels against increasing the stringency of the proposal.

While NMOGA is supportive of NMED's LDAR proposal, there are some changes that are needed to make it more workable. In suggesting these changes, NMOGA is not trying to change the stringency of the program, just make it more workable and clearer in application.

First, all the discussions of the pneumatics program were premised upon units being subject either to Table 1 or Table 2 in 20.2.50.122.B.(3). The compliance methodology in paragraph (4)(b), however, applies to all pneumatic controllers and does not distinguish between the tables. NMOGA believes this is a drafting oversight as only sources subject to each Table should be assessed for that table. NMOGA has proposed language to address this oversight in the redline below and attached. After discussion between NMOGA and NMED counsel, NMOGA understands that NMED agrees that its proposal was meant to apply on a "table" basis and agrees with the concepts set forth in the NMOGA redline.

Second, both NMED and NMOGA have discussed the importance of pneumatic controllers "necessary for safety and process reasons," which NMED has proposed to exclude from the program upon a written demonstration. *See* 20.2.50.122.B.(4)(b)(i), D.(6); Kuehn testimony, Tr. 7:2041:1-5. While all parties likely agree with Ms. Kuehn that it would be "ideal" if these units were identified prior to the start of the program, the reality is that it won't happen. To protect both the ability to maintain these units and the phase out schedule, NMOGA proposes to rename the initial "total controller count" used to determine the phase out requirements as the "total <u>historic</u> controller count" so that neither it nor the phase out requirements applicable to an owner/operator are affected by subsequent identification of controllers necessary for safety or process reasons. NMOGA understands that NMED agrees with this concept as well.

Third, and most importantly, the rule does not provide how compliance with the phase out schedule will be demonstrated on the January 1, 2024, January 1, 2027, and January 1, 2030 compliance dates. It is clear from the testimony of all parties that even though Table 1 and Table 2 are phrased "Total Required Percentage of Non-Emitting Controllers by [date]" that the real focus is on replacing natural gas driven controllers with non-emitting ones or eliminating the natural gas driven controllers entirely, without replacement. Both replacement and elimination achieve the goal of reducing emissions. For purposes of demonstrating compliance on January 1, 2024, 2027 and 2030, NMOGA thus proposes that owners/operators will track the number of emitting controllers subject to each table, calculate a percentage of emitting controllers by dividing that total by the total historic controller count for that table, multiply by 100 to make a percent, and then subtract that percent from 100, which gives the "Percentage of Non-Emitting Controllers" required to assess whether the required reduction has occurred. This approach is consistent with NMED's proposal, which states that records of non-emitting controllers are not required (see

20.2.50.122.C.(1) and 20.2.50.122.D.(1)) and has the added benefit of focusing on reductions in the number of emitting controllers, the real issue, rather than addition of non-emitting controllers. NMOGA's language to achieve this is found in new proposed 20.2.50.122.B.(4)(c). NMOGA has circulated this proposal to NMED and understands that NMED supports this concept.

Finally, NMOGA believes it is critical to enshrine in the rule language Ms. Kuehn's statement that the rule does not treat replacement of a natural gas driven controller at an existing facility as a "new" controller, but rather as an existing controller. Kuehn testimony, Tr. 7:2039:12-17. This provision is critical to the orderly phase out of controllers. If a controller failure and replacement triggered the "new" requirements, the owners and operators would be forced into unplanned conversions of entire facilities because it is not cost effective to retrofit a single controller. Bisbey-Kuehn testimony, Tr. 7:2039:12-17; McCabe testimony, Tr. 7:2092:7-11. NMOGA urges the Board to include this change to 20.2.50.122.B.(4)(a) to ensure the workability of the final rule.

For these reasons, the Board should adopt the NMED proposal, with the minor workability changes noted above, and reject proposals by other stakeholders to impose more onerous phaseout requirements.

L. Storage Vessels, 20.2.50.123 NMAC. The Board Should Adopt NMED's Storage Vessel Proposal, Except that The Threshold for Existing Single Storage Vessels Should Be Increased to 6 TPY.

NMOGA generally supports the Department's proposal for controlling storage vessels under 20.2.50.123 NMAC. NMOGA's primary remaining concern at the close of hearing was the proposed 3 tpy applicability threshold for existing single tank. As the evidence demonstrates, there are critical differences between single tanks and multi-tank batteries that make regulation at the 3 tpy threshold economically unreasonable. After further discussion with NMED and review of the technical evidence, NMED has proposed a 4 tpy threshold for these tanks in its latest draft, which is positive movement. NMOGA continues to believe that a 6 tpy threshold is appropriate for these tanks.

According to the testimony of Mr. Meyer, unlike multi-tank batteries, single tank batteries have limited headspace to allow accumulation of vapors. Whereas multi-tank batteries have adequate headspace to allow pressure buildup within the tank as emissions are slowly processed through the control, a single-tank battery's control must be able to process displaced vapors entering the headspace immediately through the control device. This behavior demands that owners and operators install larger, more expensive combustors on single tank batteries than would otherwise be required. *See generally* Tr. 9:2907:7- 24; 2912:11-2913:9 ("there are instances where you actually do need bigger equipment than is usually – than is reasonably thought to be needed. You know, again a lot of times if you have tanks with low vapor space, head space, you do need a larger combustor, you know, many times.")

The challenges from lack of headspace are compounded in New Mexico by the age and rating of many of the single tanks in service. According to Mr. Meyer, many of these tanks are older and rated for either "atmospheric" or very low pressure instead of the 16 ounces more typical of modern tanks. Tr. 9:2913:10-23. This means that the tanks can't handle much, if any, internal pressure before they must vent. It is generally not possible to control atmospheric or low pressure rated tanks, and these tanks will most likely require replacement to meet NMED's proposed standards. Tr. 9:2914:17-9:2915:2.

Due to the headspace and aging complications, the cost-per-ton of controlling single tank batteries is higher than prior NMED estimates indicated. As Mr. Meyer stated, "if you consider the rules in its entirety, hydrocarbon liquid -- hydrocarbon vapor capture during truck loadout, potential for larger combustor or control device, replacing of tanks, all these things add up, you could have a significant cost associated with especially the smaller tank, single standalone tank batteries." Tr. 9:2915:17-24; *see also* Tr. 9:2925:8-23 (responding to question from Vice Chair Trujillo-Davis).

Mr. Palmer and Mr. Meyer presented competing views of the costs of controlling single tank batteries. Mr. Palmer testified that the retrofit costs in Mr. Meyer's spreadsheet were high because they exceeded the cost of replacing the tank. Based on this observation, Mr. Palmer conducted his own analysis and replaced the allegedly excessive retrofit costs with the relatively lower costs for replacing the tank. Tr. 9:3035:15-9:3036:21. Mr. Meyer reviewed Mr. Palmer's cost-per-ton estimate and the underlying data, including the EPA's explanation of retrofit costs. Mr. Meyer determined that the CTG cost for "storage vessel retrofit, as they called it, that – in 2012 year, the $68,000 was associated with new piping, new headers, basically to bring the tank vapors to the control device." Tr. 9:3092:10-24. Mr. Meyer testified that the $68,000 (now about $72,000 in 2019$) would also have to be incurred for tank replacements and that Mr. Palmer's calculation erroneously excluded these costs. Moreover, since many single tanks will require replacement, Mr. Meyer testified that the $18,000 incurred for acquisition and installation of a new tank also needed to be included. These revisions increase the cost to approximately $101,736 for single tanks, bringing the "cost per ton of VOC reduced" to around $9,167/ton VOC at a 3 tpy level. Tr. 9:3093:7-25; 9:3094:1-5; NMOGA Exhibit 62. Regulation at this cost-per-ton would be particularly difficult for small operators who are more likely to own aging existing single storage vessels.

The 4 tpy threshold is also excessively costly at $6,890/ton VOC reduced. The following table summarizes available cost-per-ton figures for the provisions of 20.2.50 NMAC and demonstrates that, barring consideration of turbine VOC controls, the 4 tpy threshold for existing single tank batteries is more costly than any other proposal on an average cost-per-ton basis.

Emissions Source	**Average $/Ton**	**Exhibit**
Compressor Seals Turbines	$ 319.68	NMED 66
Hydrocarbon liquid transfers	$ 535.79	NMED 84
Engines - VOC	$ 990.00	NMED 57
Reciprocating Compressor Seals	$ 1,085.21	NMED 64
Glycol Dehydrators - Condensor	$ 2,033.96	NMED 77
Engines - NOx	$ 2,247.00	NMED Rebuttal 25
Storage Vessels (Average)	$ 2,695.00	NMED Rebuttal 28
Pneumatics	$ 2,744.71	NMED 95
Heaters - NOx	$ 3,010.00	NMED Rebuttal 27
Turbines - NOx	$ 3,214.00	NMED Rebuttal 26
LDAR - wellhead	$ 3,505.66	NMED 69
Glycol Dehydrators - Combustion	$ 3,919.63	NMED 77
Existing tank – 6 tpy	$ 4,593.00	NMOGA 62/NMED Reb. 28
LDAR - Non-wellhead	$ 5,099.99	NMED 69
Existing single tank – 5 tpy	$ 5,729.65	NMOGA 62
Existing single tank – 4 tpy	$ 6,890.00	NMOGA 62/NMED Reb. 28
Turbines - VOC	$ 9,608.25	NMED 59

The cost-per-ton of controlling VOC emissions from turbines is an outlier at $9,608.24/ton and should not be used to establish the ceiling of cost-effectiveness in this rule or to justify the 4 tpy threshold for existing single tanks. Turbines are expensive units, located at large facilities where millions of dollars have been invested in infrastructure and equipment. As Mr. Brindley testified, these "very expensive and very large" units range anywhere from $7 million to in excess of $10 million. Tr. 6:1806:12-14; 6:1807:4-17. Contrarily, existing single tanks are commonly associated with single well sites that are past their production prime. These sites are often owned and operated by small, independent operators who cannot afford excessively expensive controls. Testimony of Meyer, Tr. 9:2914:10-17

Eliminating the VOC turbine controls from consideration, the next highest cost-per-ton presented is for existing single tanks at the 4 tpy and 5 tpy threshold, which cost $6,890 and $5,792.64 per ton respectively. This actually understates the impact on a small operator, who will be required to spend the full cost (almost $150,000, see NMOGA Exhibit 61) upon installation and may or may not be able to get a financing. *See* Bisbey-Kuehn testimony, Tr. 3:879:16-20 ("Small and large companies may operate within the same industrial sector; however, the differences in how these companies operate in their ability to finance, and its capital, and the well size can affect their operations."). The costliest measures of 20.2.50 NMAC should not be imposed upon equipment commonly used by small operators at low-production facilities. These sources do not warrant such severe regulation.

Instead, NMOGA is advocating for an applicability threshold of 6 tons VOC for existing single tanks with a cost-effectiveness of $4,593 per ton. This is an aggressive proposal. This would make the existing single tank standards the costliest standards under 20.2.50 NMAC, with the exception of the $5099.99/ton VOC reduced threshold for leak detection and repair requirements for non-wellhead facilities under 20.2.50.116 NMAC and the turbine standards discussed above.

For these reasons, NMOGA believes that a 6 tpy threshold for single-tank tank batteries should be adopted.

M. Small Business Facilities, 20.2.50.125 NMAC.

NMOGA supports the position of IPANM on the appropriate contours of the Small Business Facilities provision.

N. Produced Water Management Units, 20.2.50.126 NMAC. The Department Should Exclude Recycling Facilities from the Definition of Produced Water Management Units.

The Department has made significant improvements to the produced water management unit standards under 20.2.50.126 NMAC by eliminating arbitrary emissions limits and unproven requirements to apply covers that route vapors to air pollution control devices. With available technology, these standards would have required the oil and gas industry to reduce the size of recycling operations and, in some cases, resort to freshwater. The Department has responded to these concerns by imposing requirements that are achievable with current technology and largely preserve industry's ability to continue recycling activities.

To further protect the industry's important recycling activities, NMOGA urges the Board to exclude recycling facilities from the definition of produced water management units altogether. Several technical witnesses have urged the Department to make this change. *See* Campsie, CDG Exhibit B, 8:9-15; Campsie, CDG Reb. Ex. B, 4:7-16; Cooper, CDG Reb. Ex. E, 7:11-18. This change is particularly important to clearly exclude recycling facilities that are not at frac ponds or pits, often called Recycle on the Fly ("ROTF") units. ROTF are a collection of temporary tanks that move around to accommodate frac schedules. These facilities do not have pits or ponds. Control options for these temporary facilities are very limited, and the tanks hold water that has already been through separation. Any further control would require supplemental fuel and a temporary flare.

The 50,000 bbl threshold contained in the definition of produced water management units will provide relief for some of these operations. NMOGA has provided minor revisions to that definition to clarify the applicability of the 50,000 bbl threshold to recycling facilities. NMOGA believes these changes are consistent with the original definition but provide additional clarity. While this clarification is helpful, NMOGA urges the Board to exclude recycling facilities altogether. A size threshold on recycling facilities does not encourage owners and operators to maximize produced water recycling, a result that is not within New Mexico's public interest.

These requested changes will help ensure that the recycling activities critical to New Mexico's future can continue unimpeded.

O. Credible Evidence, 20.2.50.127. The Board Should Adopt the Parties' Stipulation.

Under the Department's May 6, 2021, proposal at 20.2.50.127 NMAC, if "credible information" indicated that a source was not in compliance with 20.2.50, the source was "presumed to be in violation unless and until the owner or operator provide[d] credible evidence or information demonstrating otherwise." The Department has since abandoned this proposal because all parties stipulated to alternative language. NMOGA urges the Board to adopt the language as stipulated. NMED's original proposal would have allowed the department to violate its duty to conduct independent investigations and base enforcement decisions on information, not presumptions. NMSA 1978, §§ 74-2-5.1.A; 74-2-14.A. The original proposal also presented due process concerns, especially as it relates to the right to a presumption of innocence.

III. CONCLUSION

NMOGA is appreciative of the department's consideration of many of NMOGA's comments in the pre-hearing and during the hearing. NMOGA is deeply appreciative of the Board's engagement during the hearing and obvious interest in determining what controls are in the best interest of New Mexico. NMOGA offers these comments and arguments in the sincere belief that they will help the Board in reaching that best, most workable, decision for New

Mexico that balances the ozone reductions against the cost and burden on the state, its people, and its businesses and their employees.

Respectfully submitted,

HISER JOY, PLC

By: /s/ Eric L. Hiser

Eric L. Hiser
Brandon Curtis
5080 N. 40th St, Suite 245
Phoenix, AZ 85024
(480) 505-3900
ehiser@hiserjoy.com
bcurtis@hiserjoy.com

GALLAGHER & KENNEDY, P.A.

By: /s/ Dalva L. Moellenberg

Dalva L. Moellenberg
1239 Paseo de Peralta
Santa Fe, New Mexico 87501-2758
505-982-9523
DLM@gknet.com

CERTIFICATE OF SERVICE

I hereby certify that on January 20, 2022January 20, 2022, a true and correct copy of the foregoing ***Post-Hearing Brief*** was served via electronic mail to the following:

Pamela Jones
Hearing Administrator
Environmental Improvement Board
1190 Saint Francis Drive, Suite S2102
Santa Fe, New Mexico 87505
Pamela.jones@state.nm.us
Administrator for the Environmental Improvement Board

Felicia Orth
felicia.l.orth@gmail.com
Environmental Improvement Board Hearing Officer

Lara Katz, Assistant General Counsel
Office of General Counsel
New Mexico Environment Department
1190 St. Francis Drive
Santa Fe, New Mexico 87505
lara.katz@state.nm.us

Andrew Knight, Assistant General Counsel
NMED Office of General Counsel
121 Tijeras Ave. NE, Suite 1000
Albuquerque, New Mexico 87102
andrew.knight@state.nm.us
Counsel for the New Mexico Environmental Department

Elizabeth deLone Paranhos
Delone Law Inc.
1555 Jennine Place
Boulder, Colorado 80304
elizabeth@delonelaw.com
Counsel for Environmental Defense Fund

J. Scott Janoe
Baker Botts LLP
910 Louisiana Street

Karla Soloria
New Mexico Office of the Attorney General
P.O. Box 1508
Santa Fe, New Mexico 87504
ksoloria@nmag.gov
Counsel for the Environmental Improvement Board

Tannis Fox
Western Environmental Law Center
409 East Palace Avenue, #2
Santa Fe, New Mexico 87501
fox@westernlaw.org

David R. Baake
Baake Law LLC
2131 North Main Street
Las Cruces, New Mexico 88001
david@baakelaw.com
Counsel for Conservation Voters New Mexico, Diné C.A.R.E., Earthworks, Natural Resources Defense Council, San Juan Citizens Alliance, Sierra Club, and 350 New Mexico

Christopher J. Neumann
Gregory R. Tan
Casey Shpall
Greennberg Traurig, LLP
1144 Fifteenth Street, Suite 3300
Denver, CO 80202
neumannc@gtlaw.com
tangr@gtlaw.com

Houston, Texas 77002
Scott.janoe@bakerbotts.com
Counsel for Oxy USA Inc.

Ana Maria Gutiérrez
Hogan Lovells US LLP
1601 Wewatta Street, Suite 900
Denver, CO 80202
Ana.gutierrez@hoganlovells.com

Sandra Milena McCarthy
Hogan Lovells LLP
Columbia Square
555 Thirteenth Street, NW
Washington, DC 20004
Sandra.mccarthy@hoganlovells.com

Counsel for Kinder Morgan, Inc., El Paso Natural Gas Company, L.L.C., TransColorado Gas Transmission Co., LLC, and Natural Gas Pipeline Company of America, LLC

Charles de Saillan
New Mexico Environmental Law Center
1405 Luisa Street, Suite 5
Santa Fe, New Mexico 87505
cdesaillan@nmelc.org
Legal Counsel for New Mexico Environmental Law Center

Jeffrey Holmstead
Tim Wilkins
Whit Swift
Bracewell LLP
111 Congress Avenue, Suite 2300
Austin, Texas 78701
Jeff.holmstead@bracewell.com
Tim.wilkins@bracewell.com
Whit.swift@bracewell.com

Stuart R. Butzier
Christina C. Sheehan
Modrall, Sperling, Roehl, Harris & Sisk, PA
PO Box 2168
Albuquerque, New Mexico 87103-2162
srb@modrall.com
shpallc@gtlaw.com
Counsel for NGL Energy Partners LP, Solaris Water Midstream, Owl Swd Operating LLC, and Goodnight Midstream, LLC

Matthias L. Sayer
NGL Energy Partners LP
125 Lincoln Ave, Suite 222
Santa Fe, NM 87501
Matthias.sayer@nglep.com
Legal Counsel for NGL Energy Partners, LP

Christopher L. Colclasure
Beatty & Wozniak, P.C.
216 16th Street, Suite 1100
Denver, CO 80202
ccolclasure@bwenergylaw.com
Counsel for 3 Bear Delaware Operating – NM, LLC

Leslie Witherspoon, Manager, Environmental Programs
9330 Sky Park Court
MZ:SP3-Q
San Diego, CA 92123-5398
Witherspoon_leslie_h@solarturbines.com
Solar Turbines, Inc.

Louis W. Rose
Kari Olson
Ricardo S. Gonzales
Montgomery & Andrews, PA
P.O. Box 2307
Santa Fe, NM 87504
lrose@montand.com
kolson@montand.com
rgonzales@montand.com
Legal Counsel for Independent Petroleum Association of New Mexico

Daniel Jaynes
Keifer Johnson
Gabriel Pacyniak
Natural Resources & Environmental Law Clinic, University of New Mexico
1117 Stanford Dr NE

ccs@modrall.com
Legal Counsel for The Gas Compressor Association

Matthew A. Nykiel
3798 Marshal St., Ste. 8
Wheat Ridge, CO 80033
mnykiel@wildearthguardians.org

Daniel L. Timmons
301 N. Guadalupe St, Ste. 201
Santa Fe, NM 87501
dtimmons@wildearthguardians.org
Legal Counsel for Wild Earth Guardians

Albuquerque, New Mexico 87106
jaynesda@law.unm.edu
johnsoke@law.unm.edu
pacyniak@law.unm.edu
Legal Counsel for Center for Civic Policy and NAVA Education Project

Lisa Devore, Air Quality Specialist, Intermountain Region
John Vimont, Branch Chief, Air Resources Division
National Park Service

/s/ Eric L. Hiser

Eric L. Hiser

STATE OF NEW MEXICO

BEFORE THE ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF:

PROPOSED NEW REGULATION
20.2.50 **No. EIB 21-27 (R)**
Oil and Gas Sector – Ozone Precursor Pollutants

NMOGA'S PROPOSED STATEMENT OF REASONS

INTRODUCTION

1. The matter comes before the New Mexico Environmental Improvement Board (the "Board") upon a petition filed by the New Mexico Environment Department ("NMED" or "Department") proposing adoption of 20.2.50 NMAC,[1] which sets forth standards to regulate ozone precursor pollutants from the oil and gas sector.

2. NMED filed the petition for regulatory change on May 6, 2021. On June 8, 2021, issued an Order of Hearing Determination and Hearing Officer Appointment. The order scheduled the public hearing to begin September 20, 2021. The order directed parties intending to present technical testimony to submit notices of intent to present direct technical testimony, including written testimony and exhibits, by July 28, 2021. The order also directed such parties to submit pre-filed rebuttal testimony and exhibits no later than September 6, 2021. The Board appointed Felicia Orth to act as hearing officer.

3. The following parties submitted entries of appearance in this matter: Conservation Voters New Mexico; Dine C.A.R.E.; Earthworks; Natural Resources Defense Council; San Juan Citizens Alliance; Sierra Club; 350 New Mexico; Environmental Defense Fund; New Mexico

[1] Unless otherwise specified, all references to 20.2.50 NMAC refer to the Department's December 16, 2021 redline circulated to the parties. The Department circulated another draft on January 18, 2022. Where significant, we refer to changes made therein.

Oil and Gas Association; Oxy USA Inc.; Kinder Morgan, Inc.; El Paso Natural Gas Company, LLC; Transcolorado Gas Transmission Co., LLC; Natural gas Pipeline Company of America, LLC; NGL Energy Partners LP; Solaris Water Midstream, LLC; OWL SWD Operating, LLC; Goodnight Midstream, LLC.; Independent Petroleum Association of New Mexico; New Mexico Environmental Law Center; Center for Civic Policy and NAVA Education Project; 350 Santa Fe; and The Gas Compressor Association.

4. The parties submitted pre-filed written direct technical testimony on Jul 28, 2021, and pre-filed written rebuttal technical testimony on September 6, 2021.

5. The hearing began on September 20, 2021, in Santa Fe, New Mexico and concluded on October 1, 2021. The hearing was conducted virtually due to the COVID-19 pandemic. The public had ample opportunity to participate in the hearing.

6. This petition seeks the adoption of state-only rules. The rule is not intended to be submitted to the U.S. Environmental Protection Agency ("EPA") for integration into New Mexico's State Implementation Plan. Baca Testimony, Tr. 1:259:5-9.

LEGAL AUTHORITY

7. Congress enacted the Clean Air Act ("CAA") in 1970 to address a variety of air pollution problems. A central piece of this legislation was the directive that the Environmental Protection Agency ("EPA") promulgate primary and secondary national ambient air quality standards ("NAAQS") for six criteria pollutants: PM10 and PM2.5, SO2, NO2, CO, lead and ozone. 42 U.S.C. 7409(a).

8. Primary standards must be set at the level necessary to protect public health, secondary NAAQS must be set at the level necessary to protect the public welfare from any known or anticipated adverse effects, and both standards must be set with an adequate margin of

safety. EPA must review the standards every 5 years to evaluate their adequacy and, if necessary, make adjustments. Within 3 years of EPA setting a standard, each state must develop and submit a state implementation plan ("SIP") to EPA that provides for the implementation, maintenance, and enforcement of the NAAQS within each air quality control region of the state.

9. The federal CAA also requires EPA to develop various other standards to combat air pollution, including standards for new sources of air pollution, 42 U.S.C. 7411, standards for sources of hazardous air pollutants, *Id.* 7412, and standards for the construction of new major sources and major modifications of existing major sources. 42 U.S.C., Chapter 85, Subchapter I, Parts C and D.

10. New Mexico has responsibility under the Clean Air Act to ensure federal standards are met. The NAAQS, SIPs, and other federal standards serve as minimum requirements for sources of air pollution throughout the country, and states cannot authorize or allow operation of sources in ways that contravene these federal requirements.

11. State authority to combat air pollution is not limited to implementing those standards necessary to attain and maintain the NAAQS or implement other federal CAA requirements. States may adopt or enforce any emissions standard or requirement respecting control or abatement of air pollution that is more stringent than federal law, so long as state law authorizes such measures and the provisions are not impermissible for some other reason, such as federal preemption. 42 U.S.C. 7416.

12. The state law governing Board's authority to issue rules in this rulemaking is NMSA 1978, § 74-2-5.C, which requires the Board to adopt a plan, including rules, to control emissions of oxides of nitrogen and volatile organic compounds to provide for attainment and

maintenance of the primary ozone NAAQS in areas of the state where the ozone concentrations exceed ninety-five percent of the primary NAAQS.

13. The legislature has imposed meaningful limits on Board's rulemaking authority under this section. The Board must both determine that there is substantial evidence to support the exercise of the limited statutory authority for this rulemaking and must consider a number of factors specified in the Air Quality Control Act in weighing the evidence and determining how to act on this petition for rulemaking.

14. Under New Mexico's Open Meeting law, the Board must provide "reasonable notice to the public" of any meetings where a majority or quorum of the Board discusses the adoption of a proposed rule, regulation or formal action. NMSA 1978, § 10-15-1. "Compliance with prescribed notice requirements is a prerequisite to any valid action by a government entity, and failure to give proper notice constitutes a jurisdictional defect rendering action of that entity null and void." N.M. Att'y Gen. Op. No. 90-29 (Dec. 20, 1990). The Board cannot issues rules that go beyond the substance of the public notice.

15. The Board also must consider and "give the weight it deems appropriate to all facts and circumstances, including: (1) character and degree of injury to or interference with health, welfare, visibility and property; the public interest, including the social and economic value of the sources and subjects of air contaminants; and technical practicability and economic reasonableness of reducing or eliminating air contaminants from the sources involved and previous experience with equipment and methods available to control the air contaminants involved." While the Board has latitude in assigning weight to these factors, it must *consider* each to determine the weight that should be assigned.

16. The Board cannot issue state rules more stringent than the federal counterparts unless it makes a "determination, based on substantial evidence and after notice and public hearing, that the proposed rule will be more protective of public health and the environment." NMSA 1978, § 74-2-5.G. This requires the Board to find, based on substantial evidence, that the proposed standard will provide greater protection to public health and the environment by improving the state's ability to attain and maintain the ozone NAAQS. *See* § 74-2-5.G (requiring rule to be "more protective of public health and the environment"); 42 U.S.C. 7409(b) (requiring NAAQS to be protective of public health and welfare).

17. Proposals that call for control of air toxics or control of ozone precursors in ways that do not demonstrably mitigate ozone are not within the Board's authority in this rulemaking because the statutory authority relied upon under NMSA 1978, § 74-2-5.C. and the public notice provided do not contemplate adopting rules that do not benefit the attainment and maintenance of the ozone NAAQS as part of this rulemaking.

18. A proposal must provide a demonstrable benefit towards attaining or maintaining the primary ozone standard. If a proposal does not, it is not made "to provide for attainment and maintenance of the standard," and it is beyond the scope of Board's authority under NMSA 1978, § 74-2-5.C.

NMOGA WITNESSES

19. Several technical witnesses provided testimony on behalf of NMOGA.

20. John Smitherman, Senior Advisor to NMOGA, provided testimony regarding the scope of the rule's coverage under 20.2.50.2 NMAC; various definitions under 20.2.50.7 NMAC; engines and turbines under 20.2.50.113 NMAC; compressor seals under 20.2.50.114 NMAC; leak detection and repair under 20.2.50.116 NMAC; natural gas well liquid unloading

under 20.2.50.117 NMAC; hydrocarbon liquid transfers under 20.2.50.120 NMAC; pig launching and receiving under 20.2.50.121 NMAC; pneumatic controllers and pumps under 20.2.50.122 NMAC; storage vessels under 20.2.50.123 NMAC; and well workovers under 20.2.50.124 NMAC. Mr. Smitherman was a credible witness.

21. Adam Meyer, Principal/VP of US Operations for Valor EPC, provided testimony regarding control devices and related definitions under 20.2.50.115 NMAC; pneumatic controllers and pumps under 20.2.50.122 NMAC; and storage vessels under 20.2.50.123 NMAC. Mr. Meyer was a credible witness.

22. Justin Lisowski, Rotating Equipment Engineer for Valor EPC, provided testimony regarding engines and turbines under 20.2.50.113 NMAC; compressor seals under 20.2.50.114 NMAC; and heaters under 20.2.50.119 NMAC. Justin Lisowski was a credible witness.

23. Dennis McNally, Senior Scientist at Alpine Geophysics, LLC, provided testimony regarding the modeling impacts of proposed 20.2.50 NMAC. Mr. McNally was a credible witness.

24. Ken Nichols, National Practice Leader for Geologic Carbon Sequestration at Tetratech, testified regarding the Department's produced water management unit proposal under 20.2.50.126 NMAC. Mr. Nichols was a credible witness.

25. John Dunham, Managing Partner at Dunham & Associates, provided testimony regarding the economic impacts of proposed 20.2.50 NMAC. Mr. Dunham was a credible witness.

26. Marise Textor, Senior Advisory Consultant at EHS Regulatory Strategies & Advocacy, provided testimony on glycol dehydrator standards under 20.2.50.118 NMAC and pig launching and receiving standards under 20.2.50.121 NMAC. Ms. Textor was a credible witness.

MODELING & OZONE IMPACTS

27. The Board is authorized to adopt a plan, including rules, to control emissions of oxides of nitrogen and volatile organic compounds. NMSA 1978, § 74-2-5.C. This authority is limited to those measures necessary "to provide for attainment and maintenance of the standard." *Id*.

28. To assess the impacts of proposed Part 50, NMED contracted with a team consisting of the Western States Air Resource Council and Ramboll US Consulting, Inc. to conduct photochemical grid modeling ("PGM") in support of the Department's Ozone Attainment Initiative. The study was conducted from April 2020 to May 2021.

29. The PGM is the best evidence on whether the rule provides "for attainment and maintenance of the standard."

30. Ralph Morris, witness for NMED; Dennis McNally, witness for NMOGA; Mr. Blewitt, witness for IPANM; and Tammy Thompson, witness for EDF testified regarding the ozone impacts of proposed part 50 in New Mexico based on the PGM.

31. Ralph Morris testified that the "requirements of Part 50 are estimated to reduce projected 2028 future year ozone design values at New Mexico monitoring sites by between -0.2 to -1.5 ppb." NMED Exhibit 106:11:9-11. This impact ranges from .28% to 2.14% of the 70-ppb standard.

32. Ralph Morris testified further that "given its mostly rural nature, . . . ozone formation due to New Mexico anthropogenic emissions is primarily NOx sensitive across most of New Mexico," although some isolated areas exhibit greater VOC sensitivity on some days. NMED Exhibit 106:61:3-12.

33. The modeling also shows that most ozone in NM is from emission sources outside of New Mexico or from biogenic emissions within New Mexico, which are not related to oil and gas activity. NMOGA Exhibit A4:11:18-19.

34. Despite the significant controls imposed by part 50, the "ozone air quality benefits of the proposed rule are quite modest, and what impacts the rule does have are primarily the result of the NOx control measures. Additional controls on oil and gas VOC emissions are not an effective means of controlling ambient ozone levels in New Mexico, except for possibly in a very limited area in northeastern San Juan County." NMOGA Exhibit A4:16.

35. Mr. Morris testified that adding 670 tons of NOx emissions would have "no material effect on ozone results." Tr. 2:381:1-12; 2:398:9-14. As such, if any standard anticipated to provide reductions less than this threshold are not adopted and the anticipated reductions are added back to the inventory, the increase will not have an impact on ozone attainment or maintenance. Moreover, because most areas are VOC sensitive, emissions increases or reductions of greater than 670 tons per year of VOC would also have no material effect on ozone results in most of New Mexico. This is also supported by the testimony of Mr. McNally who testified that adding or subtracting VOC emissions in excess of a thousand tons of VOC would have no demonstrable impacts on ozone concentrations. Tr. 2:494:22-25 – 495:1-5

36. The Board puts significant weight on the fact that some VOC controls do not demonstrably reduce ozone concentrations in meaningful ways. The Board finds that VOC controls that do not reduce emissions by at least 1,000 tons VOC are not warranted because there is not adequate evidence to conclude that they will meet the objectives of this rulemaking.

ECONOMIC REASONABLENESS

37. The Board is required to give the weight it deems appropriate to the "economic reasonableness" of the proposed rule. NMSA 1978, § 74-2-5.G.

38. The Board finds that oil and gas production in New Mexico is a significant contributor to economic activity in the state and generates significant tax revenue and royalties.

39. John Dunham, technical witness for NMOGA, supplied the only comprehensive economic analysis of the rule. NMOGA Exhibit A6. NMED did not supply a comprehensive economic analysis, although it provided rebuttal testimony responding to Mr. Dunham's analysis. NMED Rebuttal Exhibit 19.

40. Mr. Dunham testified that "the rule would cost oil and natural gas producers in the state a minimum of $3.8 billion 2020 dollars in direct administrative and operational costs over a 5-year period, with the bulk of these costs occurring in the first year or two." NMOGA Exhibit A6:2:13-15. Mr. Dunham estimated that this "could lead to a loss of as many as 3,217 jobs in the petroleum production industry in New Mexico and cost the state's economy $674.2 million annually. In addition, the state and its localities would receive almost $22.9 million less in tax revenue from businesses and employees in the oil and gas industry. This does not include reduced royalty and severance tax revenues resulting from lower production." Exhibit A6, "Estimated Costs of Proposed Ozone Precursor Rule on Oil and Natural Gas Development in New Mexico," at 1.

41. NMED witnesses Brian Palmer and Susan Day testified that Mr. Dunham's cost estimates were not well supported. NMED Rebuttal Exhibit 19. NMED estimated the costs of the rule to be $338 million per year, amounting to $1.7 billion in costs over 5 years. NMED Rebuttal Exhibit 19:2:19. NMED witnesses later revised this estimate to be $215 million per year or $1.1 billion in costs over 5 years. Tr. 3:795:5-10.

42. Unlike the $3.8 billion 5-year cost provided by Mr. Dunham, Mr. Palmer and Ms. Day's 5-year estimate of $1.1 billion did not include all costs for the life of the rule. Tr. 3:820:4-7. NMED witnesses testified that they estimated the costs of the rule would be incurred over 15 years instead of 5 years. Tr. 3:808:8-17. Based on NMED's estimated annualized costs of $215 million per year, the total costs of the rule over 15 years would be $3.2 billion. Tr. 3:832:13-16. Although NMED witnesses testified that they lacked sufficient information to evaluate Mr. Dunham's report and identified miscellaneous errors, NMED's $3.2 billion estimates for the total cost of the rule is consistent with Mr. Dunham's $3.8 billion estimate and confirms that the rule will have significant impacts on the New Mexico economy.

43. Board gives significant weight to the economic impacts of the rule. As detailed below, Board finds that adopting provisions of the proposal that impose significant costs without providing a commensurately significant contribution to ozone reductions would not be consistent with Board's mandate to consider economic reasonableness.

SCOPE, 20.2.50.2 NMAC

44. Per 20.2.50.2 NMAC, NMED's proposal would apply "to sources located within areas of the state under the Board's jurisdiction that, as of the effective date of this Part or anytime thereafter, are causing or contributing to ambient ozone concentrations that exceed ninety-five percent of the national ambient air quality standard for ozone, as measured by a design value calculated and based on data from one or more Department monitors. As of the effective date, sources located in the following counties of the state are subject to this Part: Chaves, Dona Ana, Eddy, Lea, Rio Arriba, Sandoval, San Juan, and Valencia."

45. The design value is the three-year average of the fourth highest maximum daily average 8-hour ozone concentration based on quality assured monitoring data. The Department

has defined the geographical applicability of the rule by the design value measured within a county. Having chosen the "county" as a basis for its proposed rule, the Department must justify its proposal on that basis by demonstrating that the counties that would be subject to regulation have a design value exceeding 95% of the primary standard.

46. The Board's authority to adopt regulations is limited to those areas of the state exceeding 95 percent of the primary NAAQS: "Rules adopted pursuant to this subsection shall be limited to sources of emissions within the area of the state where the ozone concentrations exceed ninety-five percent of the primary national ambient air quality standard." NMSA 1978, § 74-2-5.C.

47. If an area of the state does not have a design value established or does not have a design value exceeding 95% of the standard, the Board lacks authority to promulgate regulations under NMSA 1978, § 74-2-5.C.

48. The only monitor in Rio Arriba County has a design value less than 95% of the ozone NAAQS. Tr. 1:301:17-21. The Board lacks authority to apply this rule to Rio Arriba County.

49. Chavez County does not have a design value established. Tr. 1:191:12-18. Although Chavez County "contributes" to the ozone problem, the "contribution" aspect of Section 74-2-5.C goes to the types of sources contributing to the ozone problem and not to the areas of the state subject to the rule. Because Chavez County does not have an established design value, the Board lacks authority to apply this rule to Chavez County.

50. The Board finds that it lacks a statutory basis to apply Part 50 to sources located within Chavez and Rio Arriba County.

DEFINITIONS, 20.2.50.7 NMAC

51. Mr. Meyer, witness for NMOGA, testified credibly that some emissions cannot be avoided during maintenance of a closed vent system. The current NMED proposal requires that there be “no loss of VOC emissions,” which the Board finds is not technically feasible. The Board finds that the phrase “during operation” should be added to the end of the definition of “Closed Vent System” at 20.2.50.7.F NMAC to address this concern, consistent with NMOGA’s final redline of 20.2.50 NMAC submitted on January 20, 2022 (hereinafter “NMOGA Final Redline”).

52. The definition of “Control Device” under 20.2.50.7.K NMAC excludes “VRU or other equipment used primarily as process equipment.” Ms. Bisbey-Kuehn testified that “the Department intends to regulate only those vapor recovery units utilized to meet the emission standards under this part . . . within section 115, and so process VRUs are not regulated under Section 115.” The Board finds that VRUs operated primarily as process equipment are not being operated as control devices and do not meet the definition of a “Control Device” under 20.2.50.7.K NMAC.

53. The definition of “Design Value” under 20.2.50.7.M NMAC is necessary to clarify section 20.2.50.2 NMAC, which uses the term “design value” to describe how the Department evaluates which counties exceed 95% of the primary ozone standard. Tr. Mr. Baca, 1:317:4-8. Based on witness testimony, the Board finds that design values are calculated based on monitoring data obtained from monitoring stations. Mr. Ahr, witness for NMED, testified, “The NAAQS is met at an ambient air monitoring site when the three-year average of the fourth-highest daily maximum 8-hour average ozone concentration, or the design value, is less than” the standard. Tr. 1:187:18-25. Mr. Ahr also confirmed that “those counties without a monitoring station don’t have . . . design values calculated.” Tr. 1:193:2-6. To clarify the nature of how

design values are determined, the Board finds that the phrase "at an ambient ozone monitor" should be appended to 20.2.50.7.M NMAC, consistent with the NMOGA Final Redline.

54. Mr. Smitherman testified that there can be a significant time delay between when a first well being served by a well production facility is completed and when it begins normal production to sales, and the phrase "but no later than the end of well completion operations" should therefore be struck. Smitherman testimony, NMOGA Exhibit 41:3:12-28. The Board adopts this change consistent with the NMOGA Final Redline.

55. The definition of existing includes the concept of modification, but modification is not otherwise defined or used throughout the Department's proposal. Instead, technical testimony indicates that reconstruction is the primary consideration. Tr. 6:1705:13-17. The Board finds that the modification concept should be removed from 20.2.50.7.P NMAC and elsewhere where it appears in the rule, consistent with the NMOGA Final Redline.

56. The definition of "Construction" under 20.2.50.7.J NMAC excludes "relocations or like-kind replacements of existing equipment." Mr. Smitherman, technical witness for NMOGA, testified credibly that if relocation or like-kind replacement of engines/compression equipment manufactured or remanufactured prior to the effective date of this rule causes an "existing" unit to have to meet "new" unit emissions requirements, it will disincentivize the industry from efficient and beneficial practices and will increase emissions due to less optimized engine/compressor sizing and less effective major maintenance. Smitherman testimony, NMOGA Exhibit 41; Tr. 3:29-39 – 4:1-21. No party provided significant testimony opposing this language. The Department testified that it agreed with this change. Bisbey-Kuehn testimony, NMED Reb. Exhibit 1:28:13-18. The Board finds this language is supported by substantial evidence and adopts it consistent with NMED and NMOGA's Final Redline.

57. The definition of "Hydrocarbon liquid" under 20.2.50.7.T NMAC excludes produced water. This has the effect of excluding produced water from the definition of "liquid transfer" under 20.2.50.7.Y NMAC. NMED supports this language. Mr. Smitherman testified that produced water contains a very small amount of hydrocarbon liquids and that regulating produced water as a hydrocarbon liquid would result in insignificant emissions reductions and high costs. Smitherman testimony, NMOGA Exhibit 41; 5:30-40; 6:6-30. The Department agreed. NMED Reb. Exhibit 1:16:15-17. No party provided significant testimony opposing this language. The Board finds this language is supported by substantial evidence and the weight of evidence.

58. The definition of "occupied area" in 20.2.50.7.FF. includes "an outdoor venue or recreation area, such as a playground, permanent sports field, amphitheater, or similar place of outdoor public assembly." On Day 8 of the hearing, Mr. Smitherman announced NMOGA's willingness to conduct weekly AVOs and quarterly OGI or Method 21 surveys. Tr. 8:2708:15-25 – 2712:1-9. Per the Board's request, Mr. Smitherman and NMOGA submitted proposed language. NMOGA Exhibit 64. In that proposal, Mr. Smitherman proposed striking the word "recreation area." NMOGA Exhibit 64:1:23. In the NMOGA Final Redline, it has proposed a similar revision, clarifying that "outdoor venue or recreation area does not include areas normally used for dispersed recreation, such as non-developed areas of national forests, parks, or similar reserves." The Board finds this latter revision provides greater clarity on the "occupied area" concept and appropriately excludes areas of dispersed recreation that would not ordinarily be considered a "place of outdoor public assembly." The Board adopts the definition of "occupied area" contained in the NMOGA Final Redline.

59. Jeremy Nichols, technical witness for WildEarth Guardians, testified that the definition of "Potential to emit" in 20.2.50.7.MM NMAC should be revised to include pre-production operations, such as well pad construction and drilling activities. Mr. Baca testified on behalf of NMED that the Department opposes making the definition of "potential to emit" inconsistent between Part 50 and the Department's permitting programs. Baca Testimony, Tr. 5:1342:9-15. Mr. Baca also testified that the proposal would infringe on another agency's jurisdiction and is not supported by emissions data, control options, or any technical or economic feasibility data. Tr. 5:1342:9-25. The Board finds that the proposal to include pre-production operations, such as well pad construction and drilling activities, in the definition of potential to emit is not supported by substantial evidence or the weight of the evidence.

60. NMED's proposed definition of "Produced water" under 20.2.50.7.NN does not include drilling liquids. Mr. Smitherman testified credibly that liquids associated with drilling should not be included in the definition of produced water because they are not produced by the well and contain extremely low quantities of VOCs, if any. NMOGA Exhibit 41:7:32-29 – 8:1-4. The Board finds that including drilling liquids in the definition of "produced water" is not supported by substantial evidence or the weight of the evidence and adopts the language in the NMOGA Final Redline.

61. The definition of "Responsible official" under 20.2.50.7.TT NMAC allows corporations to delegate responsibilities for compliance with Part 50 to any "duly authorized representative." Mr. Smitherman testified, "corporations have the ability to designate appropriate representatives who are knowledgeable and accountable regardless of their business structure." NMOGA Exhibit 41:8:14-21. The Board finds that the inclusion of any duly authorized

representative is well-founded and supported by substantial evidence and the weight of the evidence and adopts the language in NMED's final redline.

62. NMED proposes adding a definition for "Standalone tank battery" at 20.2.50.7.WW. NMAC ("a tank battery that is not designated as associated with a well site, gathering and boosting station, natural gas processing plant, or transmission compressor station"). NMED also proposes requiring under 20.2.50.7.AAA NMAC that owners and operators designate whether a tank battery is standalone or a component of another facility type, such as a well site or gathering and boosting station. Prior to this change, Mr. Smitherman testified that the use of the term "tank battery" throughout the rule was problematic because tank batteries are often components of other facility types. NMOGA Exhibit 41:8:31-39 - 9:1-10. For example, whereas section 20.2.50.114 NMAC applies to reciprocating compressors located at tank batteries, it does not apply to reciprocating compressors located at well sites. Because tank batteries are often components of well sites, owners and operators would not have clarity on whether compressors associated with tank batteries located at well sites were subject to section 114. Tr. 4:1119:1-10. NMED's proposed definition for standalone tank battery and related changes to the definition of tank battery clarify the applicability of part 50 to tank batteries and related equipment. The Board finds that NMED's proposed changes are supported by substantial evidence and the weight of the evidence.

63. The term "Tank battery" under 20.2.50.7.AAA NMAC does not include storage vessels at saltwater disposal facilities. The proposed rule also excludes saltwater disposal facilities generally from Part 50. *See* 20.2.50.111.D NMAC. Mr. Smitherman credibly testified that tanks "associated exclusively with a saltwater disposal well/facility (SWD) should not be included in the requirements of this rule as produced water routed through or stored in such tanks

contains mostly water with perhaps a very small skim of hydrocarbon liquid that is already flashed to a non-volatilizing liquid and therefore has very low potential for VOC emissions. The cost to try to manage any small amounts of vapors associated with such tanks at an SWD facility would be enormously expensive on a $/VOC emission basis and would be economically infeasible." NMOGA, Exhibit A1:13:18-24. Ms. Bisbey-Kuehn testified that it is not the intent of the Department to regulate saltwater disposal facilities. NMED Rebuttal Exhibit 1, 11:17-19. No other party presented significant testimony opposing this exclusion. The Board finds that NMED's proposal to exclude saltwater disposal facilities is supported by substantial evidence and the weight of the evidence.

64. The term "Tank Battery" under 20.2.50.7.AAA NMAC of NMED's proposal does not include storage vessels at produced water management units. Storage vessels at produced water management units are regulated under 20.2.50.126.B.3. NMAC, which requires such vessels to either be controlled consistent with section 123 requirements or be subjected to a VOC minimization plan if section 123 controls are technically infeasible without supplemental fuel. As Mr. Kim, technical witness for Commercial Disposal Group, testified, these tanks have low hydrocarbon concentrations in the vapor stream. Tr. 9:2933:6-20. Consequently, "facilities with very low emissions can end up increasing total VOC and NOx emissions with the use of supplemental fuel in order to combust the vapors." Tr. 9:2933:10-12. The Board finds that adopting an option to implement an alternative VOC minimization plan if supplemental fuel would be required to comply with section 123 requirements is reasonable and supported by substantial evidence and the weight of the evidence and adopts these concepts as they are contained in NMED's final redline.

65. The term "Storage vessel" in 20.2.50.7.ZZ NMAC does not include a "floating roof tank complying with 40 CFR Part 60, Subpart Kb." Mr. Smitherman testified that floating roof tanks do not have a head space with a gaseous area above the liquid that could contain vapors and that such tanks are more appropriately governed by standards under 40 C.F.R. Part 60, Subpart Kb. Tr. 4:1227:4-23 – 4:1228:1-7. No other party presented significant evidence on this issue. The Board finds that excluding floating roof tanks from the definition of storage vessels under Part 50 is supported by substantial evidence and the weight of the evidence.

APPLICABILITY, 20.2.50.111 NMAC

66. The Department's proposal at 20.2.50.111.B NMAC requires an engineer to perform potential to emit calculations, which would prohibit air quality consultants from performing this task. The record does not support this requirement. NMED's testimony is that requiring an engineer to perform this assessment offers a greater level of assurance in design. *See* Bisbey-Kuehn testimony, Tr. 4:1157:17-4:1158:6; 4:1161:4-22. NMED admitted, however, that an engineer is not required for even complex permitting potential to emit calculations. Bisbey-Kuehn testimony, Tr. 4:1161:23-4:1162:4. Industry representatives testified that many professional engineers have no relevant expertise and that air quality consultants or compliance specialists, versed in how the air program determines potential to emit, were likely more qualified. See Marquez testimony, 5:1474:20-5:1475:25; Oxy, Davis Testimony, Tr. 4:1183:4-19; 4:1184:4-20. (IPANM). Oxy noted that for its 645 facility and 2,745 wells, this requirement could add nearly 6,780 engineering hours, at a cost of over $800,000. Holderman testimony, Tr. 4:1195:16-4:1196:7. The Board finds that the requirement that an engineer perform potential to emit calculations is not supported by substantial evidence and the weight of the evidence and that

Part 50 should authorize a qualified air consultant to perform this task, consistent with the NMOGA Final Redline.

67. The labor required to assess the applicability of this rule is extensive. Ms. Bisbey-Kuehn testified that there are thousands of pieces of equipment subject to proposed Part 50. Bisbey-Kuehn testimony, Tr. 9:2894:8-11. Oxy noted that for its 645 facility and 2,745 wells, this requirement could add nearly 6,780 engineering hours, at a cost of over $800,000. Holderman testimony, Tr. 4:1195:16-4:1196:7. Based on this testimony, the Board finds that Part 50 should provide at least two years to complete the certified calculations required to assess applicability for existing sources.

GENERAL PROVISIONS, 20.2.50.112 NMAC

68. Part 50 requires various equipment to be maintained consistent with manufacturer specifications or good engineering and maintenance practices. Mr. Smitherman testified that manufacturer specifications may not be available, especially for older equipment. NMOGA Exhibit A1:15:13-25. Mr. Smitherman also testified that original manufacturer specifications may not always result in the best emissions-related outcomes, as these specifications are not always designed with emissions minimization in mind. NMOGA Exhibit A1:15:13-25. Operators who have worked with the equipment for several years are often in a better position to develop effective maintenance protocols. NMOGA Exhibit A1:15:13-25. To address this concern, Part 50 allows owners and operators to rely on "an alternative set of specifications, maintenance practices and schedules sufficient to operate and maintain such sources in good working order, which have been approved by qualified maintenance personnel based on engineering principles and field experience." 20.2.50.112.A.1 NMAC; Bisbey-Kuehn testimony, Tr. 5:1356:6-16. The

Board finds this requirement is an appropriate accommodation, ensures that equipment is well-maintained, and is supported by substantial evidence and the weight of evidence.

69. The Board finds that the general duty clause as articulated in 20.2.50.112.A(2) NMAC is supported by substantial evidence and provides needed clarity for the regulated industry.

70. Several sections of Part 50 require owners and operators to record a date and time stamp, including a GPS display of the location, for certain monitoring events. Within one year of the effective date, the Department has proposed to finalize and post a list of approved technologies to comply with date and time stamp requirements. Owners and operators would be required to comply with this requirement using an approved technology within two years of the effective date. As Ms. Bisbey-Kuehn and others testified, database development projects often take years. Bisbey-Kuehn testimony, Transcript 5:1370:3-8; *see also* Smitherman testimony, Tr. 5:1427:21-5:1428:25; Brown testimony, Tr. 5:1437:19-5:1439:11. The Board finds that the record supports a two-year implementation beginning on the date the Department identifies and posts the approved technology. The Board directs the Department to engage in a stakeholder process to identify technologies that accomplish the stated goals and minimize impacts to industry. In the meantime, compliance assurance is adequately provided because owners and operators are still required to keep a written or electronic record of the date and time of any affected monitoring events.[2]

71. Owners and operators are required to annually generate a Compliance Database Report (CDR) on all assets under its control that are subject to the CDR requirements of Part 50 at the time the CDR is prepared and keep the report on file for five years. Industry

[2] Note this paragraph reflects the Department's January 18, 2021 redline circulated to the parties in this matter.

representatives, responding to prior iterations of the rule, expressed concern that an annual compliance certification would be overly burdensome. Smitherman testimony, Tr. 5:1429:14-5:1430:14; Cooper testimony, Tr. 5:1492:7-5:1493:3. The Department's most recent proposal is responsive to these credible concerns and provides a helpful metric of compliance. The Board finds the CDR report contemplated under 20.2.50.112.D NMAC is reasonable, sufficient, and supported by substantial evidence and the weight of evidence.

72. Wild Earth Guardians and others testified that additional "deviation" reporting is necessary, but the record fails to demonstrate significant benefits from such reporting. The record shows this reporting would impose significant additional costs and burdens on both NMED and industry. Copeland testimony, Tr. 5:1456:24-5:1457:23. As Mr. Baca testified, this proposal would "overwhelm" the Department," "impose additional burdens that are without any public health benefits," and take the Department and industry away from the more important work of "addressing issues with compliance that have to do with emissions to the atmosphere." Tr. 5:1592:15; 1593:8-13. The Board finds that additional deviation reporting is not supported by the weight of evidence.

ENGINES & TURBINES, 20.2.50.113 NMAC

73. After extensive engagement, the Department has proposed reasonable and aggressive standards for existing and new engines and turbines, which reflects the agreement of a diverse group of stakeholders. Bisbey-Kuehn testimony, Tr. 6:1682:10-13. Although the ultimate proposal is not as stringent as the Department's initial petition, it reflects necessary adjustments based on new information provided by various technical witnesses, including the differing field and gas conditions in New Mexico, off ramps and exemptions found in other regulatory

programs not previously considered by the Department, and other technical and economic challenges. Bisbey-Kuehn testimony, Tr. 6:1701:23-6:1702:5. For example, many of the low emitting combustor (LEC) controls are already implemented on existing turbines or else they may be small bore engines where these controls are not practical. Lisowski testimony, Tr. 6:1725:17-6:1727:7. Non-selective catalytic reduction (NSCR), used on many rich burn engines, is already in place and limited in further reduction by drift issues. Lisowski testimony, Tr. 6:1729:13-6:1730:8. Selective catalytic reduction (SCR) is not cost-effective or workable in the oil field as it is too expensive and requires full-time staffing, which is not available at most facilities. Lisowski testimony, Tr. 6:1730:9-6:1731:3. Based upon this testimony and supporting testimony from Mr. Dutton, Mr. Sheldon, Ms. Witherspoon, and NMED, the Board finds existing and new engine and turbine limits are reasonable and appropriate and hereby adopts them as proposed by NMED.

74. The National Park Service in its pre-filed testimony requested that emissions limits be established for smaller engines. Multiple experts testified that the proposed limits were not achievable in a cost-effective manner and urged that they not be adopted. *See* Trent, Tr. 6:1814:9-16; Sheldon and Dutton, Tr. 6:1757:1-6:1760:13, Lisowski Tr. 9:2990:20-9:2991:20. Based on this testimony, the National Park Service withdrew its request to regulate the smaller engines. Devore testimony, Tr. 8:2399:24-8:2400:9. The Board finds that establishing emissions limits for smaller engines as originally proposed by the National Park Service is not supported by the record.

75. The Department's initial proposal applied 20.2.50.113 NMAC to nonroad engines. NMED has since revised its proposal so that proposed 20.2.50.113 NMAC does not apply to this class of engines. The Board finds that excluding non-road engines from 20.2.50.113

is proper as these engines are subject to exclusive federal control. 42 U.S.C. § 7543(e); *Engine Mfrs. Ass'n v. U.S. E.P.A.*, 88 F.3d 1075, 1087-88 (D.C. Cir. 1996).

76. The Department has proposed various measures to add flexibility in meeting emissions limits under 20.2.50.113.B NMAC. These include an alternative compliance plan option (20.2.50.113.B(10)), an alternative emission standard allowance in cases of technical impracticability or economic infeasibility (20.2.50.113.B(11)), and the incorporation of the short-term replacement engine substitution concept currently authorized in many air quality permits (20.2.50.113.B(12). Ms. Bisbey-Kuehn credibly testified that these conditions are technically sound, environmentally protective, and provide flexibility to owners and operators. Tr. 6:1690:7-25 - 1693:1-21. The Board finds these changes are supported by the record and the weight of evidence.

77. The Department has proposed various measures to clarify the monitoring requirements under 20.2.50.113.C. These include the following: equivalency between maintenance conducted consistent with an applicable NSPS or NESHAP and maintenance conducted under 20.2.50.113.C(1) NMAC (20.2.50.113.C(2)); load calculation methodologies (20.2.50.112.C(4)); testing timeframes and procedures consistent with New Source Performance Standards (20.2.50.112.C(4)(a)-(h)); and allowance to use carbon monoxide as a VOC surrogate (20.2.50.113.C(4)(i)). Ms. Bisbey-Kuehn credibly testified why these changes were made based on stakeholder feedback and technical testimony. Tr. 6:1694:8-25 - 6:1697:1-7. The Board finds these changes are supported by the record and unopposed.

COMPRESSOR SEALS, 20.2.50.114 NMAC

78. The owner or operator of a reciprocating compressor may regularly replace rod packings consistent with 20.2.50.114.B.2(a) or B.4(a) NMAC or collect emissions from the rod

packing and route them via a closed vent system to a control device, recovery system, fuel cell, or process stream. Technical witnesses for industry testified that collecting emissions from rod packing under negative pressure would introduce avoidable safety hazards and that this requirement was not necessary to achieve the emissions benefit. NMOGA Exhibit 43:12:4-17; NMOGA Exhibit A1:21:1-12. The Board finds that removing the requirement that collecting emissions from rod packing under negative pressure is prudent and supported by substantial evidence and the weight of evidence.

CONTROL DEVICES, 20.2.50.115 NMAC

79. Control devices are required under 20.2.50.115 NMAC to be adequately designed and sized to achieve the control efficiency rates required by Part 50 and to handle the "reasonably expected range" of inlet VOC or NOx concentrations or volumes. Mr. Meyer, witness for NMOGA, testified that the language "reasonably expected range" was necessary because it is not feasible to design for "unpredictable fluctuating gas compositions, atmospheric conditions, maintenance activities, failures, and upset conditions. There could be an infinite number of permutations to consider in order to design a control device" to account for all fluctuations. NMOGA Exhibit 42:6:3-7. NMED concurred that the addition of "reasonably expected range" was consistent with the intent of the requirement. Tr. 6:1880:21 – 6:1881:1-3. No other party presented testimony opposing this change. The Board finds this language is supported by substantial evidence and the weight of evidence.

80. The Department made several minor changes to 20.2.50.115 NMAC to address stakeholder concerns. These include (1) removing the EMT requirement; (2) revisions to paragraph B.3 to clarify the methods for inspection; (3) revisions to paragraph B.5 to require that the owner or operator to minimize venting of unburnt gas to the atmosphere and design the

closed vent system to handle the expected range of emissions; (4) revisions to paragraph B.5.c. to clarify that an "assessment" is appropriate; (5) revisions to paragraph C.1(c) to modify the effective date for certain monitoring requirements to two years to align with OCD regulations; and (6) revisions to paragraph E to exempt owners and operators from the requirement to install a redundant VRU if approved in a state permit. *See* NMED Rebuttal Exhibit 1, 50-56. The Board finds these changes are supported by substantial evidence and the weight of evidence.

STATEMENT OF REASON #81: IF BOARD DOES NOT ADOPT REDUNDANT CONTROL REQUIREMENT

81. Under the Department's proposed 20.2.50.115.E(1)(b), owners and operators would be required to "control VOC emissions during startup, shutdown, maintenance, or other VRU downtime with a backup control device (e.g. flare, ECD, TO) or redundant VRU during the period of VRU downtime." The Department has not estimated the costs or emissions reductions associated with a redundant control device. Because these control devices are required to be used only during "startup, shutdown, maintenance, or other VRU downtime" and such events are inherently infrequent, the emissions reductions to be gained from redundant controls are slight, while the cost of acquiring, installing, and maintaining these redundant controls are similar to the costs associated with acquiring, installing, and maintaining the primary control device. The Board finds for these reasons that the cost-per-ton reduced of the redundant control requirement is not well supported and appears excessive. The redundant control requirement also has no federal corollary and is thus more stringent. The Board finds that the minimal emissions reductions associated with redundant controls would not have a demonstrable impact on ozone concentrations.

STATEMENT OF REASON #82: IF BOARD ADOPTS REDUNDANT CONTROL REQUIREMENT

82. Under the Department's proposed 20.2.50.115.E(1)(b), owners and operators would be required to "control VOC emissions during startup, shutdown, maintenance, or other VRU downtime with a backup control device (e.g. flare, ECD, TO) or redundant VRU during the period of VRU downtime." NMOGA's Final Redline proposes not applying this requirement during a facility-wide upset because the conditions that caused the primary VRU to be down will also impact any redundant controls. The Board finds this revision is necessary to ensure the technical feasibility of the redundant control requirement.

EQUIPMENT LEAKS AND FUGITIVE EMISSIONS, 20.2.50.116 NMAC

83. Many owners and operators of oil and gas operations subject to Part 50 already conduct extensive leak detection and repair efforts pursuant to federal New Source Performance Standards under 40 C.F.R. Part 60, Subpart OOOO and OOOOa. The Board finds that leak detection and repair efforts conducted pursuant to these or any other state- or federally-mandated programs satisfy the conditions of 20.2.50.116 NMAC to the extent that they require identical or more stringent monitoring activities.

84. For existing well sites and standalone tank batteries, proposed Part 50 requires the owner or operator to comply with 20.2.50.116.C.3 within two years of the effective date. The Board finds that a similar two-year phase-in for inactive well sites, gathering and boosting stations, natural gas processing plants, and transmission compressor stations is appropriate.

85. For well sites and standalone tank batteries, proposed Part 50 would have required facilities with a PTE less than two tpy VOC to conduct annual OGI or EPA Method 21 surveys, facilities with a PTE equal to or greater than two tpy VOC and less than five tpy VOC to conduct

semiannual surveys, and facilities with a PTE equal to or greater than five tpy VOC to conduct quarterly surveys. 20.2.50.116.C(3)(b) NMAC. For gathering and boosting stations and natural gas processing plants, owners and operators would have been required to conduct quarterly surveys at facilities with a PTE less than 25 tpy VOC and monthly surveys at facilities with a PTE equal to or greater than 25 tpy. 20.2.50.116.C(3)(c) NMAC. For transmission compressor stations, owners and operators would have been required to conduct quarterly surveys or complete surveys in compliance with 40 C.F.R. Part 60, provided the federal standards are at least as stringent as the current requirements under 40 C.F.R. Part 60, Subpart OOOOa. 20.2.50.116.C(3)(d) NMAC. For well sites within 1,000 feet of an occupied area, owners and operators would have been required to conduct surveys quarterly at facilities with a PTE less than 5 tpy VOC and monthly at facilities with a PTE equal to or greater than 5 tpy VOC. 20.2.50.116.C(3)(e) NMAC. For wellhead only sites and inactive well sites, owners and operators would have been required to conduct annual surveys. 20.2.50.116.C(3)(f),(g) NMAC. The parties generally agree on the proposed leak standards for 20.2.50.116.C(3)(d),(f), and (g). The Board finds the leak survey requirements in 20.2.50.116.C(3)(d),(f), and (g) are supported by the record. The remaining leak standards remain controversial.

86. While leak detection and repair measures reduce VOC emissions, the record does not demonstrate that reducing VOC emissions will significantly redress injuries to New Mexico air quality associated with ozone. The areas of New Mexico impacted by this rule are NOx sensitive, meaning that VOC emissions reductions have a relatively modest impact on ozone concentrations, particularly in the quantities attributable to anthropogenic sources, such as oil and gas. As Mr. McNally testified, “additional controls on oil and gas VOC emissions are not an

effective means of controlling ambient ozone levels in New Mexico, except for possibly in a very limited area in northeastern San Juan County." NMOGA Exhibit A4:16.

87. VOC emissions reductions attributable to leak detection and repair measures diminish rapidly with increasing frequency. Mr. Smitherman credibly testified that most leaks are identified and repaired during initial surveys. NMED's own data demonstrates that 40% of all emissions reductions from LDAR are achieved with annual surveys, 60% are achieved with semiannual surveys, and 80% are achieved with quarterly surveys. NMOGA Exhibit 58:14. A study from the American Petroleum Institute consisting of 6,000 surveys across 3,482 sites also found less than 2 leaks per site during initial surveys, with the leak rate falling quickly to less than 1 leaking component on average in subsequent surveys. NMOGA Exhibit 25:B-2. The Board gives weight to the diminishing returns that occur with increasing leak frequency.

88. The leak detection frequencies proposed by the Department would have imposed unreasonable costs on the oil and gas industry relative to the ozone benefits projected to occur and, therefore, are not supported by the weight of evidence. The Board finds that NMOGA's methodology more credibly estimates the cost of leak detection and repair requirements. For well sites, NMOGA's analysis uses NMED's own data, except that NMOGA has used a different model plant. Smitherman testimony, Tr. 8:2673:12-25 - 2674:1-15. While NMED relied on a model plant from data developed in 1996 based on equipment surveys conducted outside of New Mexico, NMOGA relied on a model plant derived from data gathered from New Mexico oil and gas operators in 2019. Smitherman Testimony, Tr. 8:2668:1-11. NMOGA's more recent and geographically relevant data came from EPA's 2019 GHG report and showed that, on average, New Mexico sites have fewer pieces of equipment per site, fewer components per piece of equipment, and lower potential leak emissions than was observed in the 1996 study NMED has

relied upon. NMOGA Exhibit 58:9. Similarly, while NMED relied on gathering and boosting station model plant data derived from a 1996 EPA/GRI study, NMOGA relied on a 2019 Colorado State University study, which showed fewer equipment, fewer components, and lower potential leak emissions relative to NMED's data. Smitherman testimony, Tr. 8:2678:23-25 - 2679:1; NMOGA Exhibit 28; NMOGA Exhibit 58:28. By relying on more current and geographically relevant model plant data, the Board finds that NMOGA has put forward a more credible methodology for estimating the costs of LDAR for New Mexico oil and gas operators at varying frequencies and thresholds.

89. Based on this more refined analysis, the Board finds that the incremental costs of the greater frequencies at the lower thresholds proposed by NMED are not economically reasonable. As the emissions reductions available reduces with increased frequency, the per-survey cost of conducting LDAR remains relatively the same, meaning that less emissions per dollar are reduced with each survey. Smitherman testimony, Tr. 8:2688:11-15. NMOGA's technical testimony demonstrates that the incremental costs associated with increasing LDAR frequency are exorbitant. NMOGA Exhibit 58:46-48, 50, 54-56. For example, under NMOGA's proposal, an oil well site with a PTE of 4 tpy VOC would be required to conduct an annual survey, while NMED's proposal would require a semiannual survey. The cost-per-ton of VOC reduced of going from an annual to semiannual survey is between $16,448 and $21,028 per ton. NMOGA Exhibit 58. Given the limited impact of VOC reduction on ozone, adopting a semiannual frequency for such facilities would be inconsistent with the Board's duty to consider and give the weight it deems appropriate to economic reasonableness and the proposal's capacity to redress the targeted injury.

90. The Board finds that the leak survey frequencies proposed in the NMOGA Final Redline at 20.2.50.116.C.3(b)-(c) NMAC are reasonable and supported by substantial evidence and the weight of evidence.

91. The Department has also endorsed the leak detection and repair proposal requiring owners and operators of well sites within 1,000 feet of an occupied area to conduct quarterly surveys at sites with less than 5 tpy VOC and monthly surveys at sites with 5 tpy or more VOC. 20.2.50.116.C.3(e) NMAC. Increasing LDAR within one-thousand feet of an occupied area is not related to reducing ozone concentrations for those targeted locales. Instead, as Ms. Lee Ann Hill, witness for CAA testified, the concern driving the LDAR proximity proposal is the direct emissions of VOCs and hazardous air pollutants, not the secondary ozone that may form as the results of these direct emissions. Tr. 9:2847:21-25 – 2849:1-6. When questioned about whether ozone would form within 1,000 feet of the wellhead, Ms. Hill testified that she had "not personally evaluated ozone formation given particular distances from oil and gas sites." *See* Tr. 9:2848:15-21. Other witnesses questioned on this point did not provide testimony or evidence that ozone formation within 1,000 feet of a well site is occurring or will be prevented by the implementation of this standard in a way that will meaningfully contribute to the attainment and maintenance of the primary ozone standard. *See, e.g.,* Tr. 8:2730:4-25 – 2735:1-11.

92. Because the LDAR proximity proposal has no federal corollary, it is more stringent than federal requirements and is subject to NMSA 1978, § 74-2-5.G. Given that the record contains no evidence that ozone forms within 1,000 feet of a wellhead, the Board has no evidence upon which to conclude the standard is more protective of the primary benefits targeted by this rulemaking, ozone reductions. The statutory authority for this rulemaking and the public

notice provided do not contemplate regulation of direct emissions for purposes unrelated to ozone formation. Adopting such standards as part of this rulemaking would deprive the public of fair notice and exceed the operative statutory authority, contrary to law. This does not foreclose the Department or any other party from petitioning the Board to adopt these standards in a different context.

93. The Department declined the invitation to revise Part 50 to make clear that a leak, in and of itself, is not a violation if repaired. As Ms. Bisbey-Kuehn explained, "There may be instances where the Department discovers egregious violations from leaking components that present an imminent and substantial danger to human health or the environment or repeated leaks from the same components that indicate a systemic pattern of failure by the owner or operator to maintain sources and components in good working order." Tr. 8:2458:13-19. The Board finds that, based on the weight of substantial evidence, violations of Part 50 for leaking equipment should be limited to instances of failure to repair consistent with 20.2.50.116 NMAC or instances when the Department identifies "leaking components that present an imminent and substantial danger to human health or the environment or repeated leaks from the same components that indicate a systemic pattern of failure."

NATURAL GAS WELL LIQUID UNLOADING, 20.2.50.117 NMAC

94. The Department's proposal for natural gas well liquid unloading under 20.2.50.117 NMAC only apply to unloading events that result "in the venting of natural gas." Mr. Smitherman testified that the rule should be modified to recognize that only manual liquid unloading events that result in venting of gas to the atmosphere are covered, since there is no

benefit to emissions reductions to apply the requirements to activities that do not cause emissions. NMOGA Exhibit A1:25:1-46. The Board finds that limiting section 20.2.50.117 NMAC to hydrocarbon liquid unloading events that cause emissions is supported by substantial evidence and the weight of evidence.

95. The Department's proposal includes automatic control systems as an option for controlling hydrocarbon liquid unloading events. Mr. Smitherman testified that these systems help minimize venting volumes by detecting the end of an unloading event and triggering the actuation of the valve to send gas back to the facilities and sales. NMOGA Exhibit A1:25:29-36. Mr. Smitherman testified further that allowing use of the automated control system will encourage development of these smart systems. The Board finds that encouraging use of this proven technology is prudent and supported by substantial evidence and the weight of evidence. Smitherman testimony, NMOGA Exhibit A1:25:41-46.

GLYCOL DEHYDRATORS, 20.2.50.118 NMAC

96. The NMED made a variety of minor changes to clarify the intent of 20.2.50.118 NMAC in response to stakeholder concerns, including the addition of "if present" to 20.2.50.118.B.1-2 to address the concern that not all glycol dehydrators have flash tanks; replacing the term "natural gas" with the term "vapor" in 20.2.50.118.B.3(b); and revising the venting prohibition in 20.2.50.118.B(3)(b) to only prohibit direct venting to the atmosphere during normal operations. These unopposed changes are supported by the credible testimony of NMOGA witness, Marise Textor. NMOGA Exhibit 46:14:16-45 – 15:1-16. The Board finds they are supported by substantial evidence and the weight of evidence.

97. The Department's proposal at 20.2.50.118.C(1) NMAC requires owners or operators to conduct an extended gas analysis on the dehydrator inlet gas. Ms. Textor credibly

testified that a representative gas analysis would provide an accurate basis upon which to estimate emissions and that an extended gas analysis may add significant costs the rule that NMED has not accounted for. NMOGA Exhibit 46:15:18-37. In rebuttal, Ms. Bisbey-Kuehn testified that calculations based on the actual composition would be more accurate, but she does not provide any indication of how significant this difference is or whether the costs for such analyses have been accounted for. NMED Rebuttal Exhibit 1:73:6-13. The Board finds that it lacks evidentiary basis to conclude that a representative gas analysis fails to provide an adequate estimate of emissions and finds that a representative gas analysis should be authorized under 20.2.50.118.C(1) NMAC, based on the weight of substantial evidence

98. The Department's proposal at 20.2.50.118.B(3)(b), which allows 5% downtime, conflicts with the VRU requirements in section 20.2.50.115.E NMAC, which requires use of a redundant VRU during downtime. NMOGA Exhibit 46:15:39-46 – 16:1-16. To address potential confusion, the Board finds that the 5% downtime allowance supersedes the VRU backup requirements in 20.2.50.115.E NMAC and has added clarifying language suggested by NMOGA, based on substantial evidence and the weight of the evidence

HEATERS, 20.2.50.119 NMAC

99. Mr. Lisowski, technical witness for NMOGA, testified regarding the relationship between CO and NOx reductions, `explaining that reductions in CO may cause an increase in NOx. NMOGA Exhibit 43:12:31-32. Mr. Lisowski testified further that NMED did not provide data to demonstrate that the CO limit originally proposed would not interfere with achieving the proposed NOx emissions limit. NMOGA Exhibit 43:12:32-33. The Department adjusted the CO limit to 400 ppmvd @ 3% O2 to address this testimony. The Board finds this CO limit adjustment is supported by substantial evidence and the weight of evidence.

HYDROCARBON LIQUID TRANSFERS, 20.2.50.120 NMAC

100. Prior versions of 20.2.50.120 NMAC did not clearly exclude liquid transfers involving produced water and applied to production facilities and associated tank batteries delivering liquids directly to pipelines. Mr. Smitherman credibly testified that regulating such sources presents technical challenges, would not be cost-effective, and would not result in significant emissions reductions. NMOGA Exhibit A1:26:1-46 – 27:1-12. The Department's latest proposal adjusts the rule to address this testimony, and the Board finds these revisions are supported by substantial evidence and the weight of evidence.

101. The Department's January 18, 2022 proposal would require hydrocarbon liquid transfers at existing gathering and boosting stations (including associated tank batteries) without any controlled storage vessels to be controlled consistent with the schedule specified in Paragraph 1 of Subsection B of 20.2.50.123 NMAC. The Department adopted this standard to resolve a discrepancy between the default two-year timeline for hydrocarbon liquid loading and the graduated timeline for storage vessel controls in 20.2.50.123 NMAC. Many gathering and boosting sites route vapors back to existing tanks without existing controls during transfer events. These operators cannot practically retrofit their entire inventory of storage vessels with combustion controls within two years for the same reason that owners and operators of storage vessels generally need a phase-in under 20.2.50.123.B.(1) NMAC. Holderman, Tr. 9:2898:17-25 - 2900:1-9. For this reason, the Board finds that hydrocarbon liquid transfers subject to 20.2.50.120 NMAC at existing gathering and boosting stations (including associated tank batteries) without any controlled storage vessels must control those operations consistent with the schedule in 20.2.50.123.B.(1) NMAC.

102. The Department's latest proposal exempts facilities from section 20.2.50.120 NMAC that perform less than 13 loadouts per year. 20.2.50.120.A NMAC. This exemption is based on the testimony of Mr. Smitherman, who testified that hydrocarbon liquid transfers are a function of event frequency, that sites that perform liquid transfer infrequently have a low emitting potential, and that the required controls are not warranted on a cost-per-ton basis for low-emitting operations. NMOGA Exhibit A1:27:15-26. The Board finds that substantial evidence and the weight of evidence supports adoption of this exemption.

103. The Department's current proposal requires industry to visually inspect hydrocarbon liquid transfer equipment monthly at staffed locations and semiannually at unstaffed locations. 20.2.50.120.C.1 NMAC. These requirements reflect the testimony of Mr. Smitherman who testified to the logistical challenges and administrative burden of conducting inspections more frequently particularly when sites are unmanned or remotely located. NMOGA Exhibit A1:28:37-46. The Board finds these inspection frequencies are supported by substantial evidence and the weight of evidence and reflect a reasonable strategy for evaluating compliance with hydrocarbon liquid transfer requirements.

104. Section 20.2.50.20.C(3) of the May 6, 2021 version of the Department's proposal required owners and operators to transfer hydrocarbon liquids using only trucks and rail cars tested annually to meet certain vapor tightness standards. The Department subsequently removed these requirements. The Board finds it is preempted under federal law from adopting the vapor tightness standards previously proposed. Under 49 U.S.C. § 5125(b), the proposed vapor tightness standards are preempted because they impose more stringent testing requirements on hazardous material containers than federal hazardous material transportation law. Similarly, under the Interstate Commerce Commission Termination Act of 1995 ("ICCTA"), proposed

section 120 vapor tightness standards are federally preempted as they relate to rail shipments because they have the effect of managing or governing rail transportation, an area of regulation reserved to the federal government. The Board also finds it imprudent to apply vapor tightness testing standards to oil and gas owners and operators because these entities rarely own or operate the trucks and rail cars used to transport hydrocarbon liquids. NMOGA Exhibit A1:1-14.

PIG LAUNCHING & RECEIVING, 20.2.50.121 NMAC

105. Ms. Bisbey-Kuehn testified that NMED estimates overall emissions reductions of 22.9 tons of allowable VOC emissions from implementation of the proposed standards for pig launching and receiving under 20.2.50.121 NMAC. Tr. 9:3053:5-11. Ms. Bisbey-Kuehn testified this number did not account for all emissions because the Department's emissions inventory is not complete. *Id.* But even if the emissions were underestimated by a factor of 45, they would not move the ozone needle according to the testimony of Mr. McNally and Mr. Morris.

106. Because the Department's pig launching and receiving standards have no federal counterpart, these standards are more stringent than existing federal law. As such, they trigger the protectiveness evaluation in NMSA 1978, § 74-2-5.G. A statement that the requisite information to justify the rule is not available is not substantial evidence and does not give the Board an adequate basis to adopt these standards.

ALTERNATIVE STATEMENTS OF REASON #107-111 IF BOARD ADOPTS 20.2.50.121 NMAC

107. The standards in proposed 20.2.50.121 NMAC apply to individual pipeline pig launcher or receiver operations with a PTE equal to or greater than one tpy VOC located within the property boundary of, and under common ownership or control with, well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and transmission

compressor stations. This language limits the applicability of the rule by counting the 1 tpy threshold against individual pig launchers ot receivers and requiring that the equipment be located within the property boundary of another site. These modifications are responsive to the credible testimony of NMOGA witness, Marise Textor. She testified that pig launching and receiving operations have a low emissions potential and have not been regulated in several other contexts due to these low emissions; that controlling VOC emissions from pig launching and receiving through NOx-producing combustion technologies would not be prudent given the NOx sensitivity of many areas covered by the rule; that controlling off-site pig launchers and receivers would pose several infrastructure and logistical challenges; and that NMED underestimated costs of controlling emissions from pig launching and receiving. NMOGA Exhibit 46:3:39-46 – 8:1-27. The Board finds these limits to the applicability of 20.2.50.121 NMAC are supported by substantial evidence and the weight of evidence.

108. The standards in proposed 20.2.50.121.B NMAC require capturing and reducing VOC emissions from pigging operations by at least ninety-five percent. If a combustion device is used, the combustion device must have a minimum design combustion efficiency of ninety-eight percent. This combustion efficiency standard is supported by the testimony of multiple witnesses who testified that, in practice, 98% destruction efficiency is not continuously achievable due to factors such as variability of field conditions. *See, e.g.,* NMOGA Exhibit 46:8:29-46 – 9:1-19. The Board finds that a 95% control efficiency with a 98% destruction efficiency design is supported by substantial evidence and the weight of evidence.

109. Under proposed 20.2.50.121.B(2)(b) NMAC, the owner or operator conducting an affected pig launching or receiving operation must, among other things, employ a method to "prevent" emissions, such as installing a liquid ramp or drain, routing a high-pressure chamber to

a low-pressure line or vessel, using a ball valve type chamber, or using multiple pig chambers. 20.2.50.121.B(2)(b) NMAC. Based on the unrefuted testimony of Ms. Textor, while these measures "minimize" emissions, they do not "prevent" them. NMOGA Exhibit 46:10:7-27. The NMOGA Final Redline recommends replacing the word "prevent" with the word "minimize" to address this issue. The Board finds this revision is supported by substantial evidence and the weight of evidence.

110. Under proposed 20.2.50.121.C(1) NMAC, the owner or operator of an affected pig launching or receiving site must inspect the equipment for leaks using AVO, RM 21, or OGI on either a monthly basis if pigging operations at a site occur on a monthly basis or more frequently or prior to the commencement and after the conclusion of the pig launching or receiving operation, if less frequent. The allowance to perform less than monthly inspections is responsive to Ms. Textor's testimony that many pig launching and receiving operations occur less frequently than monthly and that no emissions benefit would be achieved from inspecting these sites on a monthly basis when pig launching and receiving is not taking place. NMOGA Exhibit 46:11:14-41. The Board finds these inspections frequencies are supported by substantial evidence and the weight of evidence.

111. Under proposed 20.2.50.121.B(4) and C(3) NMAC, NMOGA has requested that portable control devices used to comply with pig launching and receiving control requirements not be subject to 20.2.50.115 NMAC. Instead, NMOGA proposes these devices comply with manufacturer specifications. NMOGA witness, Marise Textor, testified that portable devices may not have all the monitoring capability that can be installed on fixed equipment and that portable control equipment rental companies may not permit owners and operators to make the necessary changes to meet 20.2.50.115 NMAC. Ms. Textor testified that installing such devices

consistent with manufacturer specifications ensures the equipment will be used optimally. The Board finds the proposed changes in 20.2.50.121.B(4) and C(3) of the NMOGA Final Redline are supported by substantial evidence and the weight of evidence.

PNEUMATIC CONTROLLERS & PUMPS, 20.2.50.122 NMAC

112. NMED's proposal requires all new natural gas-driven pneumatic controls to have an emission rate of zero and a specified percentage of existing pneumatic controllers to be non-emitting according to the schedule in proposed 20.2.50.122.B(3) NMAC. The proposal ultimately requires anywhere from 80 to 90% of pneumatic controllers at well sites, tank batteries, and gathering and boosting stations to be non-emitting by January 1, 2030, and 98% of pneumatic controllers at transmission compressor stations and gas processing plants to be non-emitting by January 1, 2030. The proposal also requires new pneumatic diaphragm pumps located at natural gas processing plants to be non-emitting; new pneumatic diaphragm pumps located at well sites, tank batteries, gathering and boosting stations, or transmission compressor stations with access to commercial line electrical power to be non-emitting; existing pneumatic diaphragm pumps located at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, or transmission compressor stations with access to commercial line electrical power to be non-emitting within two years; and certain pneumatic diaphragm pumps to be controlled by 95% where non-emitting technology is unavailable. The Board finds this proposal is aggressive, reasonable, and supported by the records and hereby adopts NMED's December 16th redline, with the exceptions noted below.

113. The Department's pneumatics proposal received opposition from multiple parties. The Department received several requests for revising the standard, including adopting a production-based approach rather than a controller-count approach; requiring owners and

operators to achieve a fixed increase in the percentage of non-emitting controllers; requiring gas driven controllers at gas processing plants or transmission compressor stations to be converted to non-emitting within six months; accelerating the timeline so that all retrofits occur by 2025 rather than 2030; and removing the early action incentive in NMED's proposal. The Board finds these requests are not supported by substantial evidence in the record or the weight of evidence.

114. These requests are largely based on testimony that similar measures have been undertaken in Colorado. However, the Board finds that the record adequately demonstrates that Colorado's approach to pneumatic regulation is not appropriate for New Mexico. Bisbey-Kuehn testimony, Tr. 7:2025:20-25 - 2027:1-15. Colorado has been regulating pneumatic controllers since 2009 and has extensive infrastructure and administrative resources in place necessary to administer its program. Palmer Testimony, Tr. 7:2022:19-23; Bisbey-Kuehn testimony, Tr. 7:2026:12-22. This is not the situation New Mexico finds itself in, as the state is regulating pneumatic controllers for the first time through proposed Part 50. Bisbey-Kuehn testimony, Tr. 7:2027:4-9. The Department's proposal respects the status of the industry in New Mexico while requiring leaps forward to achieve significant emissions reductions.

115. Multiple witnesses with direct experience designing systems, planning retrofits, and grappling with current supply chain issues testified that the Clean Air Advocates' accelerated phaseout proposal is unrealistic. *See, e.g.,* Tr. 7:2214:14-18; 2283:1-8; 2284:9 – 2285:25. More importantly, as Mr. McNally testified, "The earlier imposition of VOC controls would have little impact on ozone levels in NM." NMOGA Exhibit 45:8. For this reason, the Board does not find that this added stringency is necessary to assist New Mexico in attaining and maintaining the ozone primary standard and is not supported by the weight of evidence

116. The Board finds that leak detection and repair requirements for pneumatic controllers as proposed at 20.2.50.122.C(6) NMAC is supported by substantial evidence in the record. Multiple

witnesses testified that there are "significant emissions from malfunctioning gas-powered pneumatic controllers" and that applying LDAR to these devices would reduce emissions from these malfunction events. *See, e.g.,* Tr. 7:60:6-9; 7:2224:8-24. The Board also finds that imposing LDAR on these units significantly reduces the urgency of phasing them out. NMED Rebuttal Exhibit 23, 20.2.50.116.C NMAC. If these malfunctioning devices are being identified and repaired, then New Mexico has less to gain by hastening their replacement. Tr. 7:2275:4-14.

117. While the Board finds the Department's pneumatics proposal is supported by the record, NMOGA has identified some implementation issues that require minor revision of the standard. These changes are consistent with the stringency and intent of the Department's proposal and are supported by the record.

118. The pneumatics program is premised upon units being subject either to Table 1 or Table 2 in 20.2.50.122.B.(3). The compliance methodology in paragraph (4)(b), however, applies to all pneumatic controllers and does not distinguish between the tables. The Board adopts the language in the NMOGA Final Redline, 20.2.50.122.B(4)(b)(i)-(v) NMAC, which clarifies that the compliance demonstration is conducted on a per-table basis.

119. The Department has proposed to exclude pneumatic controllers "necessary for safety and process reasons" from the total controller count. *See* 20.2.50.122.B.(4)(b)(i), D.(6) NMAC; Bisbey-Kuehn testimony, Tr. 7:2041:1-5. The total controller count is the denominator used when calculating a facility's percentage of non-emitting controllers. *See* 20.2.50.122.B.(4)(b)(i) NMAC. This provision does not contemplate that some of these controllers may not be discovered until after the total controller count has been completed on July 1, 2023. However, the identification of pneumatic controllers necessary for safety and process reasons units is critical to the rule's success. If these units are not identified, the total controller count will not be accurate, and an owner or operator's ability to continue to operate

these units if they are not timely identified is put in question. To address these concerns, the NMOGA Final Redline proposes to rename the initial "total controller count" used to determine the phase out requirements as the "total historic controller count." The Board finds these minor changes are consistent with the Department's intent and the weight of the evidentiary record.

120. The Board also finds that the Department's pneumatics proposal should more directly articulate how compliance is demonstrated. It is clear from the testimony of all parties that even though Table 1 and Table 2 are phrased "Total Required Percentage of Non-Emitting Controllers by [date]" that the real focus is on replacing natural gas driven controllers with non-emitting ones or eliminating the natural gas driven controllers entirely, without replacement. Both replacement and elimination achieve the goal of reducing emissions. For purposes of demonstrating compliance on January 1, 2024, 2027 and 2030, the NMOGA Final Redline has proposed that owners/operators track the number of emitting controllers subject to each table, calculate a percentage of emitting controllers by dividing that total by the total historic controller count for that table, multiply by 100 to make a percent, and then subtract that percent from 100, which gives the "Percentage of Non-Emitting Controllers" required to assess whether the required reduction has occurred. *See* NMOGA Final Redline, 20.2.50.122.C.(4)(c). This approach is consistent with NMED's proposal, which states that records of non-emitting controllers are not required (see 20.2.50.122.C.(1) and 20.2.50.122.D.(1)). This approach also ensures that reductions in emitting controllers are accounted for, rather than simply the addition of non-emitting controllers. The Board finds this language is supported by the weight of evidence in the record and provides additional clarity on how to demonstrate compliance with the Department's proposal under 20.2.50.122 NMAC.

121. The Board also finds that the Department's proposal should be revised to clarify requirements for new pneumatic controllers. Ms. Bisbey-Kuehn testified that the rule does not treat replacement of a natural gas drive controller at an existing facility as a "new" controller, but rather as an existing controller. Bisbey-Kuehn testimony, Tr. 7:2039:12-17. If a controller failure and replacement triggered the "new" requirements, the owners and operators would be forced into unplanned conversions of entire facilities because it is not cost effective to retrofit a single controller. Bisbey-Kuehn testimony, Tr. 7:2039:12-17. This was not the Department's intent. Bisbey-Kuehn testimony, Tr. 7:2039:12-17. To clarify the rule consistent with this testimony, the Board adopts the clarifying language in the NMOGA Final Redline, 20.2.50.122.B.(4)(a) NMAC.

STORAGE VESSELS, 20.2.50.123 NMAC

122. The Department has proposed to regulate new storage vessels with a PTE of 2 tpy or more of VOCs, existing storage vessels within multi-tank batteries with a PTE of 3 tpy or more, and existing single storage vessels with a PTE of 4 tpy or more of VOCs. The Board finds these standards are more stringent than their federal counterpart under 40 C.F.R. Part 60, Subparts OOOO and OOOOa, which regulates storage tanks at a 6 tpy threshold. Accordingly, these standards are subject to NMSA 1978, § 74-2-5.G.

123. The evidence indicates that, unlike multi-tank batteries, single tanks have limited headspace to allow accumulation of vapors. Whereas multi-tank batteries have adequate headspace to allow pressure buildup within the tank as emissions are slowly processed through the control, a single tank's control must be able to process displaced vapors entering the headspace immediately through the control device. This behavior demands that owners and operators install larger, more expensive combustors on single tanks than would otherwise be

required. *See generally* Meyer testimony, Tr. 9:2907:7- 24; 2912:11-2913:9. The challenges from lack of headspace are compounded in New Mexico for existing tanks, which are older and rated for either "atmospheric" or very low pressure instead of the 16 ounces more typical of modern tanks. Tr. 9:2913:10-23. This means that the tanks can't handle much, if any, internal pressure before they must vent. These tanks will most likely require replacement to meet NMED's proposed standards. Tr. 9:2914:17-9:2915:2.

124. Due to these factors, the record indicates the cost of controlling existing single tanks at the 4 tpy threshold is approximately $6,890 per ton of VOC reduced. NMOGA Exhibit 62; NMED Rebuttal Exhibit 28. The Board finds this cost is excessive.

125. Other than turbine VOC controls, the 4 tpy threshold proposal for existing single tanks is more costly than any other proposal on an average cost-per-ton basis.

126. The appropriate cost-per-ton threshold depends on the source type. Bisbey-Kuehn testimony, Tr. 6:1704:11-13. The cost-per-ton of controlling VOC emissions from turbines is an outlier at $9,608/ton. NMED Exhibit 59. Turbines are located at large facilities where millions of dollars have been invested in infrastructure and equipment. As Mr. Brindley testified, these "very expensive and very large" units range anywhere from $7 million to in excess of $10 million. Tr. 6:1806:12-14; 6:1807:4-17. On the contrary, existing single tanks are frequently located at small and aging production sites. Small operators would be required to spend nearly $150,000 upon installation to comply and could have difficulty obtaining financing. NMOGA Exhibit 61. The Board finds this cost-per-ton threshold is not appropriate for existing single tanks, which are commonly owned and operated by small operators with minimal resources for further investment. Meyer testimony, Tr. 9:2914:10-17

127. The next highest cost-per-ton proposed in the rule by NMED is for requirements applicable to non-wellhead facilities under 20.2.50.116 NMAC, which require an investment of $5099.99 per ton VOC reduced. The Board finds this is a more appropriate point of comparison for evaluating the economic reasonableness of existing single tank controls. Existing single tanks at the 4 tpy and 5 tpy threshold would cost $6,890 and $5,792.64 per ton respectively, a cost that exceeds the $5099.99 per ton VOC reduced associated with 20.2.50.116 NMAC for non-wellhead facilities. NMOGA 62; NMED Reb. Exhibit 28. The Board finds that it would be economically unreasonable to impose the costliest measures of 20.2.50 NMAC on a per-ton basis on equipment commonly used by small operators at low-production facilities. Regulating single existing storage vessels at a threshold of 6 tons VOC has a cost-effectiveness of $4,593 per ton. The Board finds this is a reasonable threshold for regulation of existing single storage tanks.

WORKOVERS, 20.2.50.124 NMAC

128. According to NMED witness, Mr. Palmer, "emissions estimates for workover operations are not currently available in the modeling emissions inventory or found in the NMED equipment data. Therefore, we do not have an estimate of emission reductions from well workovers." Tr. 9:3101:19-23. The workover proposal has no federal counterpart and is thus subject to the heightened substantial evidence standard in NMSA 1978, § 74-2-5.G. Because the record contains no evidence on the amount of VOCs reduced or whether such reductions have any impact on ozone, the Board finds that the record does not support adoption of the standard.

PRODUCED WATER MANAGEMENT UNITS, 20.2.50.126 NMAC

129. The Department's initial proposal for 20.2.50.126 NMAC received significant feedback as technical testimony demonstrated issues with proposed emissions limits and their potential impact on water recycling activities. The Board finds it is in the best interest of New

Mexico to not hinder water recycling and reuse. The Department's most recent proposal responds to these concerns by imposing requirements that are achievable with current technology and largely preserve owners' and operators' ability to continue recycling activities.

130. Industry stakeholders have urged the Board to further protect the industry's recycling activities by excluding "recycling facility" from the definition of produced water management units altogether. *See* Campsie, CDG Exhibit B, 8:9-15; Campsie, CDG Reb. Ex. B, 4:7-16; Cooper, CDG Reb. Ex. E, 7:11-18. This change is particularly important to clearly exclude recycling facilities that are not at frac ponds or pits, often called Recycle on the Fly ("ROTF") units. ROTF units are a collection of temporary tanks that move around to accommodate frac schedules. These facilities do not have pits or ponds. The water held in these tanks have already been through separation, and imposing section 20.2.50.126 NMAC—which requires separation—on these units will not meaningfully reduce emissions. Any further control would require supplemental fuel and a temporary flare. The Board finds this change is warranted to further preserve the industry's ability to recycle water.

131. Industry stakeholders also provided extensive testimony that supplemental fuel may be needed to control storage vessels associated with produced water management units. *See, e.g.,* Kim testimony, Tr. 7:2290:6-13. Technical testimony also shows that this may not be technically feasible and may not provide a net environmental benefit. Kim testimony, Tr. 7:2290:6-13. To address this and related concerns, the Department has proposed that, within two years of the effective date for an existing tank associated with PWMUs or upon startup of a new storage vessel associated with PWMUs, owners and operators must either control the storage vessel in accordance with the requirements of Section 20.2.50.123 or submit a VOC minimization plan to the Department demonstrating that controlling VOC emissions from

storage vessels associated with the PWMU in accordance with the requirements of Section 20.2.50.123 NMAC is technically infeasible without supplemental fuel. The Board finds this proposal is supported by substantial evidence and the weight of the evidentiary record.

CREDIBLE EVIDENCE, 20.2.50.127 NMAC

132. The parties reached a stipulation regarding the credible evidence provisions in 20.2.50.127 NMAC. The Board finds that prior language that presumed the liability of regulated entities and placed the burden of disproving third-party allegations on owners and operators was unreasonable, inconsistent with the Department's obligation to perform its own investigations, and incompatible with principles of due process. Bisbey-Kuehn Testimony, Tr. 6:1979:23-25 – 1982:1:20. The Board finds that the stipulated language adequately addresses these deficiencies and preserves the Department's ability to enforce Part 50.

Respectfully submitted,

HISER JOY, PLC

By: /s/ Eric L. Hiser

Eric L. Hiser
Brandon Curtis
5080 N. 40th St, Suite 245
Phoenix, AZ 85024
(480) 505-3900
ehiser@hiserjoy.com
bcurtis@hiserjoy.com

GALLAGHER & KENNEDY, P.A.

By: /s/ Dalva L. Moellenberg

Dalva L. Moellenberg
1239 Paseo de Peralta
Santa Fe, New Mexico 87501-2758
505-982-9523
DLM@gknet.com

<u>**CERTIFICATE OF SERVICE**</u>

I hereby certify that on January 20, 2022, a true and correct copy of the foregoing ***Statement of Reasons*** was served via electronic mail to the following:

Pamela Jones
Hearing Administrator
Environmental Improvement Board
1190 Saint Francis Drive, Suite S2102
Santa Fe, New Mexico 87505
Pamela.jones@state.nm.us
Administrator for the Environmental Improvement Board

Felicia Orth
felicia.l.orth@gmail.com
Environmental Improvement Board Hearing Officer

Lara Katz, Assistant General Counsel
Office of General Counsel
New Mexico Environment Department
1190 St. Francis Drive
Santa Fe, New Mexico 87505
lara.katz@state.nm.us

Andrew Knight, Assistant General Counsel
NMED Office of General Counsel
121 Tijeras Ave. NE, Suite 1000
Albuquerque, New Mexico 87102
andrew.knight@state.nm.us
Counsel for the New Mexico Environmental Department

Elizabeth deLone Paranhos
Delone Law Inc.
1555 Jennine Place
Boulder, Colorado 80304
elizabeth@delonelaw.com
Counsel for Environmental Defense Fund

J. Scott Janoe
Baker Botts LLP
910 Louisiana Street

Karla Soloria
New Mexico Office of the Attorney General
P.O. Box 1508
Santa Fe, New Mexico 87504
ksoloria@nmag.gov
Counsel for the Environmental Improvement Board

Tannis Fox
Western Environmental Law Center
409 East Palace Avenue, #2
Santa Fe, New Mexico 87501
fox@westernlaw.org

David R. Baake
Baake Law LLC
2131 North Main Street
Las Cruces, New Mexico 88001
david@baakelaw.com
Counsel for Conservation Voters New Mexico, Diné C.A.R.E., Earthworks, Natural Resources Defense Council, San Juan Citizens Alliance, Sierra Club, and 350 New Mexico

Christopher J. Neumann
Gregory R. Tan
Casey Shpall
Greennberg Traurig, LLP
1144 Fifteenth Street, Suite 3300
Denver, CO 80202
neumannc@gtlaw.com
tangr@gtlaw.com

Houston, Texas 77002
Scott.janoe@bakerbotts.com
Counsel for Oxy USA Inc.

Ana Maria Gutiérrez
Hogan Lovells US LLP
1601 Wewatta Street, Suite 900
Denver, CO 80202
Ana.gutierrez@hoganlovells.com

Sandra Milena McCarthy
Hogan Lovells LLP
Columbia Square
555 Thirteenth Street, NW
Washington, DC 20004
Sandra.mccarthy@hoganlovells.com

Counsel for Kinder Morgan, Inc., El Paso Natural Gas Company, L.L.C., TransColorado Gas Transmission Co., LLC, and Natural Gas Pipeline Company of America, LLC

Charles de Saillan
New Mexico Environmental Law Center
1405 Luisa Street, Suite 5
Santa Fe, New Mexico 87505
cdesaillan@nmelc.org
Legal Counsel for New Mexico Environmental Law Center

Jeffrey Holmstead
Tim Wilkins
Whit Swift
Bracewell LLP
111 Congress Avenue, Suite 2300
Austin, Texas 78701
Jeff.holmstead@bracewell.com
Tim.wilkins@bracewell.com
Whit.swift@bracewell.com

Stuart R. Butzier
Christina C. Sheehan
Modrall, Sperling, Roehl, Harris & Sisk, PA
PO Box 2168
Albuquerque, New Mexico 87103-2162
srb@modrall.com
shpallc@gtlaw.com
Counsel for NGL Energy Partners LP, Solaris Water Midstream, Owl Swd Operating LLC, and Goodnight Midstream, LLC

Matthias L. Sayer
NGL Energy Partners LP
125 Lincoln Ave, Suite 222
Santa Fe, NM 87501
Matthias.sayer@nglep.com
Legal Counsel for NGL Energy Partners, LP

Christopher L. Colclasure
Beatty & Wozniak, P.C.
216 16th Street, Suite 1100
Denver, CO 80202
ccolclasure@bwenergylaw.com
Counsel for 3 Bear Delaware Operating – NM, LLC

Leslie Witherspoon, Manager, Environmental Programs
9330 Sky Park Court
MZ:SP3-Q
San Diego, CA 92123-5398
Witherspoon_leslie_h@solarturbines.com
Solar Turbines, Inc.

Louis W. Rose
Kari Olson
Ricardo S. Gonzales
Montgomery & Andrews, PA
P.O. Box 2307
Santa Fe, NM 87504
lrose@montand.com
kolson@montand.com
rgonzales@montand.com
Legal Counsel for Independent Petroleum Association of New Mexico

Daniel Jaynes
Keifer Johnson
Gabriel Pacyniak
Natural Resources & Environmental Law Clinic, University of New Mexico
1117 Stanford Dr NE

ccs@modrall.com
Legal Counsel for The Gas Compressor Association

Matthew A. Nykiel
3798 Marshal St., Ste. 8
Wheat Ridge, CO 80033
mnykiel@wildearthguardians.org

Daniel L. Timmons
301 N. Guadalupe St, Ste. 201
Santa Fe, NM 87501
dtimmons@wildearthguardians.org
Legal Counsel for Wild Earth Guardians

Albuquerque, New Mexico 87106
jaynesda@law.unm.edu
johnsoke@law.unm.edu
pacyniak@law.unm.edu
Legal Counsel for Center for Civic Policy and NAVA Education Project

Lisa Devore, Air Quality Specialist, Intermountain Region
John Vimont, Branch Chief, Air Resources Division
National Park Service

/s/ Eric L. Hiser

Eric L. Hiser

TITLE 20 ENVIRONMENTAL PROTECTION
CHAPTER 2 AIR QUALITY (STATEWIDE)
PART 50 OIL AND GAS SECTOR – OZONE PRECURSOR POLLUTANTS

20.2.50.1 ISSUING AGENCY: Environmental Improvement Board.
[20.2.50.1 NMAC – N, XX/XX/2021]

20.2.50.2 SCOPE: This Part applies to sources located within areas of the state under the board's jurisdiction that, as of the effective date of this Part or anytime thereafter, are causing or contributing to ambient ozone concentrations that exceed ninety-five percent of the national ambient air quality standard for ozone, as measured by a design value calculated and based on data from one or more department monitors. As of the effective date, sources located in the following counties of the state are subject to this Part: [1]Dona Ana, Eddy, Lea, [2]Sandoval, San Juan, and Valencia.

A. If, at any time after the effective date of this Part, sources in any other area(s) of the state not previously specified are determined to be causing or contributing to ambient ozone concentrations that exceed ninety-five percent of the national ambient air quality standard for ozone, as measured by a design value calculated by the U.S. Environmental Protection Agency based on data from one or more department monitors, the department shall petition the Board to amend this Part to incorporate such areas.

(1) The notice of proposed rulemaking shall be published no less than one-hundred and eighty (180) days before sources in the affected areas will become subject to this Part, and shall include, in addition to the requirements of the Board's rulemaking procedures at 20.1.1.301 NMAC:

(a) a list of the areas that the department proposed to incorporate into this Part, and the date upon which the sources in those areas will become subject to this Part; and

(b) proposed implementation dates, consistent with the time provided in the phased implementation schedules provided for throughout this Part, for sources within the areas subject to the proposed rulemaking to come into compliance with the provisions of this Part.

(2) In any rulemaking pursuant to this Section, the Board shall be limited to consideration of only those proposed changes necessary to incorporate other areas of the state into this Part.

B. Once a source becomes subject to this Part based upon its potential to emit, all requirements of this Part that apply to the source are irrevocably effective unless the source obtains a federally enforceable limit on the potential to emit that is below the applicability thresholds established in this Part, or the relevant section contains a threshold below which the requirements no longer apply.[3]
[20.2.50.2 NMAC – N, XX/XX/2021]

20.2.50.3 STATUTORY AUTHORITY: Environmental Improvement Act, Section 74-1-1 to 74-1-16 NMSA 1978, including specifically Paragraph (4) and (7) of Subsection A of Section 74-1-8 NMSA 1978, and Air Quality Control Act, Sections 74-2-1 to 74-2-22 NMSA 1978, including specifically Subsections A, B, C, D, F, and G of Section 74-2-5 NMSA 1978 (as amended through 2021).
[20.2.50.3 NMAC - N, XX/XX/2021]

20.2.50.4 DURATION: Permanent.
[20.2.50.4 NMAC - N, XX/XX/2021]

20.2.50.5 EFFECTIVE DATE: Month XX, 2022, except where a later date is specified in another Section.
[20.2.50.5 NMAC - N, XX/XX/2021]

---

[1] The testimony does not support inclusion of Chaves County. There is no "design value" for Chaves County because it does not have an ambient monitor. Ahr testimony, Tr. 1:191:12-18. While the Department argues that Chaves County "contributes," that is not the test; whether it exceeds 95% of the NAAQS is the test. See NMOGA Closing Statement, § II.C, at 15-17.

[2] The testimony does not support inclusion of Rio Arriba County. All witnesses testified that the only ambient air quality monitor in Rio Arriba County has a current design value less than 95% of the ozone NAAQS and the Department conceded this. Baca testimony, Tr. 1:301:17-21. While the Department attempted to pivot to air quality control regions, this doesn't change the fact that the only monitor in Rio Arriba County does not exceed 95% of the design value. Under Section 74-2-5.C NMSA 1978, Rio Arriba County is not within the Board's jurisdiction.

[3] Wild Earth Guardians proposed that the Department be prohibited from issuing new permits in areas exceeding 95% of the primary ozone standard. The Board should not adopt this provision for the reasons outlined in the technical testimony. *See, e.g.,* Marquez testimony, Tr. 5:1476:2-5:1477:25.

20.2.50.6 OBJECTIVE: The objective of this Part is to establish emission standards for volatile organic compounds (VOC) and oxides of nitrogen (NO_x) for oil and gas production, processing, compression, and transmission sources.
[20.2.50.6 NMAC - N, XX/XX/2021]

20.2.50.7 DEFINITIONS: In addition to the terms defined in 20.2.2 NMAC - Definitions, as used in this Part, the following definitions apply.

A. "Approved instrument monitoring method" means an optical gas imaging, United States environmental protection agency (U.S. EPA) reference method 21 (RM 21) (40 CFR 60, Appendix B), or other instrument-based monitoring method or program approved by the department in advance and in accordance with 20.2.50 NMAC.[4]

B. "Auto-igniter" means a device that automatically attempts to relight the pilot flame of a control device in order to combust VOC emissions, or a device that will automatically attempt to combust the VOC emission stream.[5]

C. "Bleed rate" means the rate in standard cubic feet per hour at which gas is continuously vented from a pneumatic controller.[6]

D. "Calendar year" means a year beginning January 1 and ending December 31.[7]

E. "Centrifugal compressor" means a machine used for raising the pressure of natural gas by drawing in low-pressure natural gas and discharging significantly higher-pressure natural gas by means of a mechanical rotating vane or impeller. A screw, sliding vane, and liquid ring compressor is not a centrifugal compressor.[8]

F. "Closed vent system" means a system that is designed, operated, and maintained to route the VOC emissions from a source or process to a process stream or control device with no loss of VOC emissions to the atmosphere during operation.[9]

G. "Commencement of operation" means for an oil and natural gas well site, the date any permanent production equipment is in use and product is consistently flowing to a sales line, gathering line or storage vessel from the first producing well at the stationary source.[10]

H. "Component" means a pump seal, flange, pressure relief device (including thief hatch or other opening on a storage vessel), connector or valve that contains or contacts a process stream with hydrocarbons, except for components where process streams consist solely of glycol, amine, produced water, or methanol.[11]

I. "Connector" means flanged, screwed, or other joined fittings used to connect pipeline segments, tubing, pipe components (such as elbows, reducers, "T's" or valves) to each other; or a pipeline to a piece of equipment; or an instrument to a pipe, tube, or piece of equipment. A common connector is a flange. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this

---

[4] NMED has proposed to delete this definition in its January 18, 2022 redline. NMOGA has no objection to its removal.
[5] Kuehn/Palmer Testimony, NMED Exhibit 32:14:3-6. This definition was derived in part from Colorado Reg. 7, Section I.B.5.
[6] Kuehn/Palmer Testimony, NMED Exhibit 32:14:7-9. This definition was derived in part from NSPS Subpart OOOOa, 40 CFR § 60.5430a.; Smitherman testimony, Tr. 9:12-38. Mr. Smitherman testified credibly that the changes to the rule are consistent with the fact that intermittent controllers do not have a bleed rate as they support the minimization of high-bleed controllers to only where their unique capabilities are needed for safe operations. This change is supported by substantial evidence.
[7] Kuehn/Palmer testimony, NMED Exhibit 32:14:10-11. This definition implements the commonly accepted interpretation of a calendar year.
[8] Kuehn/Palmer testimony, NMED Exhibit 32:14:12-16. This definition was derived in part from NSPS Subpart OOOOa, 40 CFR § 60.5430a.
[9] Kuehn/Palmer testimony, NMED Exhibit 32:14:17-20. This definition was derived in part from language in Colorado Reg. 7, Section I.J, and NSPS Subpart OOOOa, 40 CFR § 60.5411a(a). NMOGA supports the Department's addition of "during operation" at the end of this definition.
[10] Kuehn/Palmer testimony, NMED Exhibit 32:14:21-23, 15:1-3. This definition was derived in part from Colorado Reg. 7, Section I.B.7.; Testimony of John Smitherman, NMOGA Exhibit A1:9:40-46, 10:1-6. NMOGA requests that the last phrase be struck. Mr. Smitherman testified that there can be a significant time delay between when a first well being served by a well production facility is completed and when it begins normal production to sales. The phrase "but no later than the end of well completion operations" should therefore be struck.; Smitherman rebuttal testimony, NMOGA Exhibit 41:3:12-28. Mr. Smitherman testified that the Waste Rule by the Oil Conservation Commission may extend the delay between when a well is completed and when it begins production. By removing the last sentence, the rule will be applicable the entire time that a facility is actually producing oil, gas, or produced water production.
[11] Kuehn/Palmer testimony, NMED Exhibit 32:15:4-8. This definition was derived in part from Colorado Reg. 7, Section I.B.10.

Part.[12]

J. "Construction" means fabrication, erection, or installation of a stationary source, including but not limited to temporary installations and portable stationary sources, but does not include relocations or like-kind replacements of existing equipment.[13]

K. "Control device" means air pollution control equipment or emission reduction technologies that thermally combust, chemically convert, or otherwise destroy or recover air contaminants. Examples of control devices may include but are not limited to open flares, enclosed combustion devices (ECDs), thermal oxidizers (TOs), vapor recovery units (VRUs), fuel cells, condensers, catalytic converters (oxidative, selective, and non-selective), or other emission reduction equipment. A control device may also include any other air pollution control equipment or emission reduction technologies approved by the department to comply with emission standards in this Part. A VRU or other equipment used primarily as process equipment is not considered a control device.[14]

L. "Department" means the New Mexico environment department.[15]

M. "Design value" means the 3-year average of the annual fourth-highest daily maximum 8-hour average ozone concentration at an ambient ozone monitor[16].

N. "Downtime" means the period of time when equipment is inoperable.[17]

O. "Enclosed combustion device" means a combustion device where waste gas is combusted in an enclosed chamber solely for the purpose of destruction. This may include, but is not limited to, an enclosed flare or combustor.[18]

P. "Existing" means constructed or reconstructed before the effective date of this Part and has not since been [19]reconstructed.[20]

Q. "Gathering and boosting station" means a facility, including all equipment and compressors, located downstream of a well site that collects or moves natural gas prior to the inlet of a natural gas processing plant; or prior to a natural gas transmission pipeline or transmission compressor station if no gas processing is performed; or collects, moves, or stabilizes crude oil or condensate prior to an oil transmission pipeline or other form of transportation. Gathering and boosting stations may include equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids.[21]

R. "Glycol dehydrator" means a device in which a liquid glycol absorbent, including ethylene

---

[12] Kuehn/Palmer testimony, NMED Exhibit 32:15:9-14. This definition was derived in part from Colorado Reg. 7, Section I.B.11.

[13] Kuehn/Palmer testimony, NMED Exhibit 32:15:15-18. This definition was taken from the Board's regulations at 20.2.72 NMAC – *Construction Permits*.; Smitherman testimony, NMOGA Exhibit A1:10:8-42. Mr. Smitherman testified that excluding relocations and replacements in kind ensures that operating efficiently is not discouraged when another compressor is required to match changing production rates.; Smitherman rebuttal testimony, NMOGA Exhibit 41:3:29-39, 4:1-21. Mr. Smitherman testified that 20.2.72 NMAC only relates to obtaining a construction permit, and it should not apply to regulations targeting the management of ozone precursors at existing facilities. He further testified that if relocation of engines/compression equipment manufactured or remanufactured prior to the effective date of this rule causes an "existing engine" to have to meet "new engine" emissions requirements, it will disincentivize the industry from efficient and beneficial practices and will increase emissions due to 1) less optimized engine/compressor sizing and 2) less effective major maintenance.

[14] Kuehn/Palmer testimony, NMED Exhibit 32:16:1-9. This definition was derived in part from Colorado Reg. 7, Part A, Section II.A.7. Ms. Kuehn agreed that process units are not intended to be treated as control devices and this last sentence implements that discussion. Bisbey-Kuehn testimony, Tr. 6:1889:6-19.

[15] Kuehn/Palmer testimony, NMED Exhibit 32:16:10.

[16] Change added to reflect NMED testimony. Ahr testimony, Tr. 1:187:9 - 188:2.

[17] Kuehn/Palmer testimony, NMED Exhibit 32:16:11-13. This definition was derived in part from Merriam-Webster dictionary. Adjusted based on testimony that downtime should include only time the equipment is inoperable and not when it is shutoff because the controlled process unit is not operating. Bisbey-Kuehn testimony, Tr. 4:1107:1-8.

[18] Kuehn/Palmer testimony, NMED Exhibit 32:16:14-20. The definition in Part 50 was developed during rule drafting based on the knowledge and experience of NMED technical staff.

[19] The definition of "modified" was deleted and testimony of the department was that it is only regulating construction and reconstruction. *See generally,* Tr. 6:1705:13-17.

[20] Kuehn/Palmer testimony, NMED Exhibit 32:16:21-22, 17:1-2. This definition is required because the applicability of numerous requirements and timeframes in Part 50 is based on whether a source is "existing" or "new".

[21] Kuehn/Palmer testimony, NMED Exhibit 32:17:3-6. This definition was derived in part from NSPS Subpart OOOOa, 40 CFR § 60.5430a.; Testimony of John Smitherman, NMOGA Exhibit A1:11:5-18. Mr. Smitherman testified that the definitions for various facilities that are subject to this rule should conform to the actual facilities that exist in the field using terms that are familiar to the industry and inclusive of as many expected facilities as possible, in order to eliminate confusion.; Smitherman rebuttal testimony, NMOGA Exhibit 41:5:3-30. Mr. Smitherman testified that facilities upstream of transmission systems should be included in the definition, as well as Central Delivery Points where crude oil is collected from various sources for stabilization.

glycol, diethylene glycol, or triethylene glycol, directly contacts a natural gas stream and absorbs water.[22]

S. "High-Bleed pneumatic controller" means a continuous bleed pneumatic controller that is designed to have a continuous bleed rate that emits in excess of 6 standard cubic feet per hour (scfh) of natural gas to the atmosphere.

T. "Hydrocarbon liquid" means any naturally occurring, unrefined petroleum liquid and can include oil, condensate, and intermediate hydrocarbons. Hydrocarbon liquid does not include produced water.[23]

U. "Inactive well site" means a well site where the well is not being used for beneficial purposes, such as production or monitoring, and is not being drilled, completed, repaired or worked over.

V. "Injection well site" means a well site where the well is used for the injection of air, gas, water or other fluids into an underground stratum.

W. "Intermittent pneumatic controller" means a pneumatic controller that is not designed to have a continuous bleed rate but is designed to only release natural gas above de minimis amounts to the atmosphere as part of the actuation cycle.

X. "Liquid unloading" means the removal of accumulated liquid from the wellbore that reduces or stops natural gas production.[24]

Y. "Liquid transfer" means the unloading of a hydrocarbon liquid from a storage vessel to a tanker truck or tanker rail car for transport.[25]

Z. "Local distribution company custody transfer station" means a metering station where the local distribution (LDC) company receives a natural gas supply from an upstream supplier, which may be an interstate transmission pipeline or a local natural gas producer, for delivery to customers through the LDC's intrastate transmission or distribution lines.[26]

AA. "Low-Bleed pneumatic controller" means a continuous bleed pneumatic controller that is designed to have a continuous bleed rate that emits less than or equal to 6 scfh of natural gas to the atmosphere.

BB. "Natural gas-fired heater" means an enclosed device using a controlled flame and with a primary purpose to transfer heat directly to a process material or to a heat transfer material for use in a process.[27]

CC. "Natural gas processing plant" means the processing equipment engaged in the extraction of natural gas liquid from natural gas or fractionation of mixed natural gas liquid to a natural gas product, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.[28]

DD. "New" means constructed or reconstructed on or after the effective date of this Part.[29]

EE. "Non-Emitting controller" means a device that monitors a process parameter such as liquid level, pressure, or temperature and sends a signal to a control valve in order to control the process parameter and

---

[22] Kuehn/Palmer testimony, NMED Exhibit 32:17:7-10. This definition was derived in part from Colorado Reg. 7, Section I.B.15.

[23] Kuehn/Palmer testimony, NMED Exhibit 32:17:11-13. This definition was derived in part from Colorado Reg. 7, Section I.B.16.; Smitherman testimony, NMOGA Exhibit A1:11:10-39. Mr. Smitherman testified that produced water contains a very small amount of hydrocarbon liquids. Excluding produced water from the definition is not a conceptual change but a change to increase clarity, and it is supported by substantial evidence. Smitherman rebuttal testimony, NMOGA Exhibit 41:5:30-40.

[24] Kuehn/Palmer testimony, NMED Exhibit 32:17:14-17. This definition derived from general information on EPA's Natural Gas STAR website and the EPA publication "Options for Removing Accumulated Fluid and Improving Flow in Gas Wells" (NMED Exhibit 44).

[25] Kuehn/Palmer testimony, NMED Exhibit 32:17:18-21. This definition was derived from general information from EPA's website and EPA's AP-42 Chapter 5.2 Transportation and Marketing of Petroleum Liquids, Section 5.2.2 (NMED Exhibit 43).; Smitherman testimony, NMOGA Exhibit A1:11:41-46, 12:1-6. Similar to the definition of "hydrocarbon liquid," Mr. Smitherman testified that produced water transfer should be excluded because applying the same requirements would result in very limited emissions reductions and impose high costs on trucking companies. Smitherman rebuttal testimony, NMOGA Exhibit 41:6:6-30. Mr. Smitherman testified that there are no hydrocarbon vapors discharged when transport vehicles are unloaded to a storage vessel. The requirements for capture or control of vapors associated with storage vessels are already adequately addressed in section 20.2.50.123 – Storage Vessels.

[26] Kuehn/Palmer testimony, NMED Exhibit 32:17:22-23, 18:1-3. This definition was derived from NSPS Subpart OOOOa, 40 CFR § 60.5430a.

[27] Kuehn/Palmer testimony, NMED Exhibit 32:18:10-13. This definition was derived in part from Colorado Reg. 7., Part E, section II.A.3.p.

[28] Kuehn/Palmer testimony, NMED Exhibit 32:18:14-18. This definition was derived from the NSPS Subpart OOOOa, 40 CFR § 60.5430a.

[29] Kuehn/Palmer testimony, NMED Exhibit 32:18:19-21. This definition is required because the applicability of numerous requirements and timeframes in Part 50 is based on whether a source is "existing" or "new".

does not emit natural gas to the atmosphere. Examples of non-emitting controllers include but are not limited to instrument air or inert gas pneumatic controllers, electric controllers, mechanical controllers and Routed Pneumatic Controllers.

FF. **"Occupied area"** means the following:

(1) a building or structure used as a place of residence by a person, family, or families, and includes manufactured, mobile, and modular homes, except to the extent that such manufactured, mobile, or modular home is intended for temporary occupancy or for business purposes;

(2) indoor or outdoor spaces associated with a school that students use commonly as part of their curriculum or extracurricular activities;

(3) five-thousand (5,000) or more square feet of building floor area in commercial facilities that are operating and normally occupied during working hours: and

(4) an outdoor venue or recreation area used as a place of outdoor public assembly, such as a playground, permanent sports field, amphitheater, or similar place. Outdoor venue or recreation area does not include areas normally used for dispersed recreation, such as non-developed areas of national forests, parks, or similar reserves.[30]

GG. **"Operator"** means the person or persons responsible for the overall operation of a stationary source.[31]

HH. **"Optical gas imaging (OGI)"** means an imaging technology that utilizes a high-sensitivity infrared camera designed for and capable of detecting hydrocarbons.[32]

II. **"Owner"** means the person or persons who own a stationary source or part of a stationary source.[33]

JJ. **"Permanent pit or pond"** means a pit or pond used for collection, retention, or storage of produced water or brine and is installed for longer than one year.[34]

KK. **"Pneumatic controller"** means a device that monitors a process parameter such as liquid level, pressure, or temperature and uses pressurized gas (which may be released to the atmosphere during normal operation) and sends a signal to a control valve in order to control the process parameter. Controllers that do not utilize pressurized gas are not pneumatic controllers.[35]

LL. **"Pneumatic diaphragm pump"** means a positive displacement pump powered by pressurized gas that uses the reciprocating action of flexible diaphragms in conjunction with check valves to pump a fluid. A pump in which a fluid is displaced by a piston driven by a diaphragm is not considered a diaphragm pump. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a diaphragm pump.[36]

MM. **"Potential to emit (PTE)"** means the maximum capacity of a stationary source to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on the hours of operation or

[30] Language proposed to limit the scope of the vague term "recreation area," which is sometimes used to cover national forests, parks and similar areas of dispersed recreation, which is different from places of concentrated gathering suggested by the listed activities. If "recreation area" is left in place and not limited, argument could be made that most of New Mexico is an occupied area. On Day 8 of the hearing, Mr. Smitherman announced NMOGA's willingness to conduct weekly AVOs and quarterly OGI or Method 21 surveys. Tr. 8:2708:15-25 – 2712:1-9. Per the Board's request, Mr. Smitherman and NMOGA submitted proposed language. NMOGA Exhibit 64. In that proposal, Mr. Smitherman proposed striking the word "recreation area." NMOGA Exhibit 64:1:23. These changes are consistent with that adopted testimony from Mr. Smitherman.

[31] Kuehn/Palmer testimony, NMED Exhibit 32:19:1-3. The definition was derived in part from the CAA at 42 U.S.C Section 7411.

[32] Kuehn/Palmer testimony, NMED Exhibit 32:19:4-7. This definition was derived in part from Colorado Reg. 7, Section I.B.17, and NSPS Subpart OOOOa, 40 CFR § 60.5397a.

[33] Kuehn/Palmer testimony, NMED Exhibit 32:19:8-10. This definition was derived in part from the CAA at 42 U.S.C Section 7411.

[34] Kuehn/Palmer testimony, NMED Exhibit 32:19:11-14. This definition was derived in part from the New Mexico Oil Conservation Commission's ("OCC") regulations at 19.15.17 NMAC.

[35] Kuehn/Palmer testimony, NMED Exhibit 32:19:15-18. The definition was derived in part from Colorado Reg. 7, Section III.B.10.; Testimony of John Smitherman 12:25-35. Mr. Smitherman testified that this definition should be more complete since they expect different requirements on the different types of pneumatic controllers.

[36] Kuehn/Palmer testimony, NMED Exhibit 32:19:19-22, 20:1-2. This definition was derived in part from NSPS Subpart OOOOa, 40 CFR § 60.5430a.

on the type or amount of material combusted, stored or processed, shall be treated as part of its design if the limitation is federally enforceable. The PTE for nitrogen dioxide shall be based on total oxides of nitrogen.[37]

NN. **"Produced water"** means a liquid that is an incidental byproduct from well completion and the production of oil and gas.[38]

OO. **"Produced water management unit"** means a permanent pit or pond that is a natural topographical depression, man-made excavation, or diked area formed primarily of earthen materials (although it may be lined with man-made materials), either of which is designed to accumulate produced water and has a design storage capacity equal to or greater than 50,000 barrels.[39]

PP. **"Qualified Professional Engineer"** means an individual who is licensed by a state as a professional engineer to practice one or more disciplines of engineering and who is qualified by education, technical knowledge, and experience to make the specific technical certifications required under this Part.[40]

QQ. **"Reciprocating compressor"** means a piece of equipment that increases the pressure of process gas by positive displacement, employing linear movement of a piston rod.[41]

RR. **"Reconstruction"** means a modification that results in the replacement of the components or addition of integrally related equipment to an existing source, to such an extent that the fixed capital cost of the new components or equipment exceeds fifty percent of the fixed capital cost that would be required to construct a comparable entirely new facility.[42]

[43]

TT. **"Responsible official"** means one of the following:

(1) for a corporation: president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative.

(2) for a partnership or sole proprietorship: a general partner or the proprietor, respectively.[44]

---

[37] Kuehn/Palmer testimony, NMED Exhibit 32:20:3-9. This definition was derived from the Board's air quality operating permit regulations at 20.2.70 NMAC. Wild Earth Guardians requested that this definition be revised to include pre-production operations, such as during well pad construction and drilling. Nichols testimony, Tr. 5:1300:4-14. Mr. Blewett outlined some of the practical problems with this approach. Blewett testimony, Tr. 5:1322:1-22; 5:1323:20-5:1324:24. Mr. Baca testified on behalf of NMED that the Department opposes making the definition of potential to emit inconsistent between Part 50 and the permitting programs, Baca Testimony, Tr. 5:1342:9-15, potentially interferes with another agency's jurisdiction, Baca Testimony, Tr. 5:1342:16-29, and no real evidence of equipment was introduced, Baca testimony, Tr 5:1342:20-5:1343:2. NMED also stated that this rulemaking is not intended to be about permitting. Baca testimony, Tr. 5:1345:8-16.

[38] Kuehn/Palmer testimony, NMED Exhibit 32:20:10-12. This definition was derived from the OCC's regulations at 19.15.2 NMAC. NMOGA supports the changes made by NMED. Smitherman testimony, NMOGA Exhibit A1:12: 37-47, 13:1-9. First, Mr. Smitherman testified that the word "liquid" should be used rather than "fluid." Second, liquids that are used in association with the process of drilling a new well should not be confused with "frac water" and water produced naturally along with oil and gas. Mr. Smitherman testified that the definition is clarified by striking the term "drilling for" and including liquids that stem from the completion process and from normal production after the fracture fluids have been recovered.; Smitherman rebuttal testimony, NMOGA Exhibit 41:7:32-39, 8:1-4. Mr. Smitherman testified that including liquids associated with the drilling process could lead to misapplication of rules intended for actual produced liquids including completion flowback and normal oil and gas production.

[39] Kuehn/Palmer testimony, NMED Exhibit 32:20:13-19. This definition was derived in part from the OCC's regulations at 19.15.2, 19.15.17, and 19.15.34 NMAC. The redline is supported by the testimony of industry stakeholders who have urged the Board to further protect the industry's recycling activities by excluding "recycling facility" from the definition of produced water management units. *See* Campsie testimony, CDG Exhibit B, 8:9-15; Campsie testimony, CDG Reb. Ex. B, 4:7-16; Cooper testimony, CDG Reb. Ex. E, 7:11-18.

[40] Kuehn/Palmer testimony, NMED Exhibit 32:20:20-22, 21:1-2. This definition was derived in part from NSPS Subpart OOOOa, 40 CFR § 60.5430a.

[41] Kuehn/Palmer testimony, NMED Exhibit 32:21:3-5. This definition was derived from Colorado Reg. 7, Section I.B.24.

[42] Kuehn/Palmer testimony, NMED Exhibit 32:21:6-10. This definition was derived from the Board's regulations at 20.2.72 NMAC.

[43] *See* Campsie testimony, CDG Exhibit B, 8:9-15; Campsie testimony, CDG Reb. Ex. B, 4:7-16; Cooper testimony, CDG Reb. Ex. E, 7:11-18.[44] Kuehn/Palmer testimony, NMED Exhibit 32:21:15-21. This definition was derived from the Board's operating permit regulations at 20.2.70 NMAC.; Smitherman rebuttal testimony, NMOGA Exhibit 41:8:5-30. Mr. Smitherman testified that the added language aligns with the already established definition of responsible official found in part 70 NMAC. Furthermore, a "duly authorized representative" allows for a responsible official that has a deeper understanding of what is being represented to the NMED, rather than limiting it to a representative who is in overall charge of the facility.

[44] Kuehn/Palmer testimony, NMED Exhibit 32:21:15-21. This definition was derived from the Board's operating permit

UU. "Routed pneumatic controller" means a pneumatic controller of any type that releases natural gas to a process, sales line, or to a combustion device instead of directly to the atmosphere.

VV. "Small business facility" means, for the purposes of this Part, a source that is independently owned or operated by a company that is a not a subsidiary or a division of another business, that employs no more than 10 employees at any time during the calendar year, and that has a gross annual revenue of less than $250,000. Employees include part-time, temporary, or limited service workers.[45]

WW. "Standalone tank battery" means a tank battery that is not designated as associated with a well site, gathering and boosting station, natural gas processing plant, or transmission compressor station.

XX. "Startup" means the setting into operation of air pollution control equipment or process equipment.[46]

YY. "Stationary Source" or **"source"** means any building, structure, equipment, facility, installation (including temporary installations), operation, process, or portable stationary source that emits or may emit any air contaminant. Portable stationary source means a source that can be relocated to another operating site with limited dismantling and reassembly.[47]

ZZ. "Storage vessel" means a single tank or other vessel that is designed to contain an accumulation of hydrocarbon liquid or produced water and is constructed primarily of non-earthen material including wood, concrete, steel, fiberglass, or plastic, which provide structural support. A well completion vessel that receives recovered liquid from a well after commencement of operation for a period that exceeds 60 days is considered a storage vessel. A storage vessel does not include a vessel that is skid-mounted or permanently attached to a mobile source and located at the site for less than 180 consecutive days, such as a truck or railcar; a process vessel such as a surge control vessel, bottom receiver, or knockout vessel; a pressure vessel designed to operate in excess of 204.9 kilopascals (29.72 psi) without emissions to the atmosphere; or a floating roof tank complying with 40 CFR Part 60, Subpart Kb.[48]

AAA. "Tank battery" means a storage vessel or group of storage vessels that receive or store crude oil, condensate, or produced water from a well or wells for storage. The owner or operator shall designate whether a tank battery is a standalone tank battery or is associated with a well site, gathering and boosting station, natural gas processing plant, or transmission compressor station. The owner or operator shall maintain records of this designation and make them available to the department upon request. A tank battery associated with a well site, gathering or boosting station, natural gas processing plant, or transmission compressor station is subject to the requirements in this Part for those facilities, as applicable. Tank battery does not include storage vessels at saltwater disposal facilities or produced water management units.[49]

BBB. "Temporarily abandoned well site" means an inactive well site where the well's completion interval has been isolated. The completion interval is the reservoir interval that is open to the borehole and is isolated when tubing and artificial equipment has been removed and a bottom plug has been set.

CCC. "Transmission compressor station" means a facility, including all equipment and compressors, that moves pipeline quality natural gas at increased pressure from a well site or natural gas processing plant through a transmission pipeline for ultimate delivery to the local distribution company custody transfer station, underground

---

regulations at 20.2.70 NMAC.; Smitherman rebuttal testimony, NMOGA Exhibit 41:8:5-30. Mr. Smitherman testified that the added language aligns with the already established definition of responsible official found in part 70 NMAC. Furthermore, a "duly authorized representative" allows for a responsible official that has a deeper understanding of what is being represented to the NMED, rather than limiting it to a representative who is in overall charge of the facility.

[45] Kuehn/Palmer testimony, NMED Exhibit 32:21:22-23, 22:1-5. This definition was developed during rule drafting by NMED technical staff and contractors.

[46] Kuehn/Palmer testimony, NMED Exhibit 32:22:6-8. This definition was derived from the Board's regulations at 20.2.7 NMAC – *Excess Emissions*.

[47] Kuehn/Palmer testimony, NMED Exhibit 32:22:9-14. This definition was derived from the Board's air quality construction permit regulations at 20.2.72 NMAC.

[48] Kuehn/Palmer testimony, NMED Exhibit 32:22:15-23, 23:1-2. This definition was derived in part from Colorado Reg. 7, Section I.B.27, and NSPS Subpart OOOOa, 40 CFR § 60.5365a.

[49] Smitherman testimony, Exhibit A1, 13:11-24. Mr. Smitherman testified that the term "tank battery" needs a clear definition because it is used in the rule multiple times. Furthermore, tanks that are associated exclusively with a salt water disposal well/facility (SWD) should not be included because produced water routed through or stored in such tanks contains mostly water with perhaps a very small skim of hydrocarbon liquid that is already flashed to a non-volatilizing liquid and therefore has very low potential for VOC emissions. Smitherman rebuttal testimony, NMOGA Exhibit 41:8:31-39, 9:1-10. Mr. Smitherman testified that without a clear definition, "tank battery" should not be used in the applicability sections of the rule. *See also* Tr. 4:1114-1120.

storage, or to other industrial end users. Transmission compressor stations may include equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids.[50]

DDD. "Vessel measurement system" means equipment and methods used to determine the quantity of the liquids inside a vessel (including a flowback vessel) without requiring direct access through the vessel thief hatch or other opening.

EEE. "Well workover" means the repair or stimulation of an existing production well for the purpose of restoring, prolonging, or enhancing the production of hydrocarbons.[51]

FFF. "Well site" means the equipment under the operator's control directly associated with one or more oil wells or natural gas wells upstream of the natural gas processing plant or gathering and boosting station, if any. A well site may include equipment used for extraction, collection, routing, storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and product piping. A well site does not include an injection well site.[52]

[20.2.50.7 NMAC - N, XX/XX/2021]

20.2.50.8 SEVERABILITY: If any provision of this Part, or the application of this provision to any person or circumstance is held invalid, the remainder of this Part, or the application of this provision to any person or circumstance other than those as to which it is held invalid, shall not be affected thereby.

[20.2.50.8 NMAC - N, XX/XX/2021]

20.2.50.9 CONSTRUCTION: This Part shall be liberally construed to carry out its purpose.

[20.2.50.9 NMAC - N, XX/XX/2021]

20.2.50.10 SAVINGS CLAUSE: Repeal or supersession of prior versions of this Part shall not affect administrative or judicial action initiated under those prior versions.

[20.2.50.10 NMAC - N, XX/XX/2021]

20.2.50.11 COMPLIANCE WITH OTHER REGULATIONS: Compliance with this Part does not relieve a person from the responsibility to comply with other applicable federal, state, or local laws, rules or regulations, including more stringent controls.

[20.2.50.11 NMAC - N, XX/XX/2021]

20.2.50.12 DOCUMENTS: Documents incorporated and cited in this Part may be viewed at the New Mexico environment department, air quality bureau.

[20.2.50.12 NMAC - N, XX/XX/2021]

[The Air Quality Bureau is located at 525 Camino de los Marquez, Suite 1, Santa Fe, New Mexico 87505.]

20.2.23.13-20.2.23.110 [**RESERVED**]

20.2.50.111 APPLICABILITY:

A. This Part applies to certain crude oil and natural gas production and processing equipment associated with operations that extract, collect, separate, dehydrate, store, process, transport, transmit, or handle hydrocarbon liquids or produced water in the areas specified in 20.2.50.2 NMAC and are located at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and transmission compressor stations, up to the point of the local distribution company custody transfer station.[53]

B. In determining if any source is subject to this Part, including a small business facility as defined in this Part, the owner or operator shall calculate the Potential to Emit (PTE) of such source and shall have the PTE

---

[50] Kuehn/Palmer testimony, NMED Exhibit 32:23:3-7.

[51] Kuehn/Palmer testimony, NMED Exhibit 32:23:8-10. This definition was derived from the MAP report.

[52] Kuehn/Palmer testimony, NMED Exhibit 32:23:11-16. This definition was derived from Colorado Reg. 7, Section I.B.30, and NSPS Subpart OOOOa, 40 CFR § 60.5430a.; Smitherman testimony, NMOGA Exhibit A1:14:8-19. Mr. Smitherman testified that wellheads can be located on pads with no facilities other than the well itself and some (likely buried) piping, and they can also be located on pads that contain production facilities like separators, pumps, tanks, compressors, etc.

[53] NMED agreed with NMOGA's requested insertion of the word "certain" and the striking of the word "and," and the inclusion of the words "associated with." It also substituted the word "site" for stations. Tr. 4:1157.

calculation certified by a qualified air consultant, professional engineer or inhouse engineer[54] with expertise in the operation of oil and gas equipment, vapor control systems, and pressurized liquid samples. The emission standards and requirements of this Part may not be considered in the PTE calculation required in this Section or in determining if any source is subject to this Part. The calculation shall be kept on file for a minimum of five years and shall be provided to the department upon request. This certified calculation shall be completed before startup for a new source and within two years of the effective date for existing sources[55].

C. An owner or operator of a small business facility as defined in this Part shall comply with the requirements of this Part as specified in 20.2.50.125 NMAC.

D. Oil transmission pipelines, oil refineries, natural gas transmission pipelines (except transmission compressor stations), and saltwater disposal facilities are not subject to this Part.

[20.2.50.111 NMAC - N, XX/XX/2021]

20.2.50.112 GENERAL PROVISIONS:

A. General requirements:

(1) Sources subject to emissions standards and requirements under this Part shall be operated and maintained consistent with manufacturer specifications, or good engineering and maintenance practices. When used in this Part, the term manufacturer specifications means either the original equipment manufacturer (or successor) emissions-related design specifications, maintenance practices and schedules, or an alternative set of specifications, maintenance practices and schedules sufficient to operate and maintain such sources in good working order, which have been approved by qualified maintenance personnel based on engineering principles and field experience. The owner or operator shall keep manufacturer specifications on file when available, as well as any alternative specifications that are being followed, and make them available upon request by the department. The terms of 20.2.50.112.A(1) apply any time reference to manufacturer specifications occurs in this Part.[56]

(2) Sources, including associated air pollution control equipment and monitoring equipment, subject to emission standards or requirements under this Part shall at all times, including periods of startup, shutdown, and malfunction, be operated and maintained in a manner consistent with safety and good air pollution control practices for minimizing emissions of VOC and NOx. During a period of startup, shutdown, or malfunction, this general duty to minimize emissions requires that the owner or operator reduce emissions from the affected source to the greatest extent consistent with safety and good air pollution control practices. The general duty to minimize emissions does not require the owner or operator to make any further efforts to reduce emissions beyond levels required by the applicable standard under this Part. The terms of 20.2.50.112.A(2) apply any time reference to minimizing emissions occurs in this Part.[57]

(3) Within two years of the effective date of this Part, owners and operators of a source requiring equipment monitoring, testing, or inspection shall develop and implement a data system(s) capable of storing information for each source in a manner consistent with this section. The owner or operator shall maintain information regarding each source requiring equipment monitoring, testing, or inspection in a data system(s), including the following information and the required information specified in an applicable section of this Part[58]:

(a) unique identification number;

---

[54] The record does not support NMED's insistence that only an engineer is qualified to calculate potential to emit. NMED's testimony is that they wanted a certain level of assurance in the design. See Bisbey-Kuehn testimony, Tr. 4:1157:17-4:1158:6; 4:1161:4-22. NMED admitted, however, that an engineer is not required for even complex permitting potential to emit calculations. Bisbey-Kuehn testimony, Tr. 4:1161:23-4:1162:4. Industry representatives testified that many professional engineers have no relevant expertise and that air quality consultants or compliance specialists, versed in how the air program determines potential to emit, were likely more qualified. See Smitherman testimony, Tr. 4:1172:5-21; Marquez testimony, 5:1474:20-5:1475:25; Davis Testimony, Tr. 4:1183:4-19; 4:1184:4-20. Oxy noted that for its 645 facility and 2,745 wells, this requirement could add nearly 6,780 engineering hours, at a cost of over $800,000. Holderman testimony, Tr. 4:1195:16-4:1196:7. What is important is that the engineer, consultant or inhouse staff be appropriately trained and qualified. The proposed redline revisions make the focus on the qualification of the person performing the work and will avoid hamstringing the program.

[55] The testimony is clear that there are over a hundred thousand of pieces of equipment subject to proposed Part 50. For example, Mr. Powell testified that there are 53,338 active oil and gas wells. Powell testimony, Tr. 3:741:7-16. The LDAR testimony made it clear that each well has multiple piece of equipment. Oxy noted that for its 645 facility and 2,745 wells, this requirement could add nearly 6,780 engineering hours, at a cost of over $800,000. Holderman testimony, Tr. 4:1195:16-4:1196:7. Based upon this testimony, the EIB should provide at least two years to complete the certified calculations.

[56] Bisbey-Kuehn testimony, Tr. 5:1356:6-16.

[57] Bisbey-Kuehn testimony, Tr. 5:1357:1-2, 18-25.

[58] This change is made to reflect that the substantive sections also require information.

(b) location (latitude and longitude) of the source;
(c) type of source (e.g., tank, VRU, dehydrator, pneumatic controller, etc.);
(d) for each source, the controlled VOC (and NO_x, if applicable) emissions in lbs./hr. and tpy;
(e) [59]make, model, and serial number; and
(f) a link to the manufacturer maintenance schedule or repair recommendations, or company-specific operational and maintenance practices.

(4) The data system(s) shall be maintained by the owner or operator of the facility.

(5) The owner or operator shall manage the source's record of data in the data system(s). The owner or operator shall generate a Compliance Database Report (CDR) from the information in the data system. The CDR is an electronic report maintained by the owner or operator and that can be submitted to the department upon request as required by Paragraph 3 of Subsection C and Subsection D of 20.2.50.112 NMAC.[60]

(6) The CDR is a report distinct from the owner or operator's data system(s). The department does not require access to the owner or operator's data system(s), only the CDR.

(7) The owner or operator's authorized representative must be able to access and input data in the data system(s) record for that source. That access is not required to be at any time from any location.

(8) The owner or operator shall [61]track each monitoring event, and shall comply with the following:

(a) data gathered during each monitoring or testing event shall be uploaded into the data system as soon as practicable, but no later than three business days of each compliance event, and/or when the final reports are received;

(b) certain sections of this Part require a date and time stamp, including a GPS display of the location, for certain monitoring events. No later than one year from the effective date of this Part, the department shall finalize a list of approved technologies to comply with date and time stamp requirements, and shall post the approved list on its website. Owners and operators shall comply with this requirement using an approved technology by no later than two years from the effective date of this Part.[62] Prior to such time, owners and operators may comply with this requirement by making a written or electronic record of the date and time of any affected monitoring event; and

(c) data required by this Part shall be maintained in the data system(s) for at least five years.

(9) The department for good cause[63] may request that an owner or operator retain a third party at their own expense to verify any data or information collected, reported, or recorded pursuant to this Part, and make recommendations to correct or improve the collection of data or information. Such requests may be made no more than once per year. The owner or operator shall submit a report of the verification and any recommendations made by the third party to the department by a date specified and implement the recommendations in the manner approved by the department. The owner or operator may request a hearing on whether good cause was demonstrated or whether the recommendations approved by the department must be implemented.

(10) Where Part 50 refers to applicable federal standards or requirements, the references refer to the applicable federal standards or requirements that were in effect at the time of the effective date of this Part.

(11) Prior to modifying an existing source, including but not limited to increasing a source's throughput or emissions, the owner or operator shall determine the applicability of this Part in accordance with

---

[59] NMOGA supports this deletion as the information on emissions is found in the "source" requirement of (e).
[60] The data system(s) can be one or more systems so long as they are capable of producing the compliance data report (CDR) within the required time frame. Bisbey-Kuehn testimony, Tr. 5:1368:8-19. NMOGA also appreciates the new terminology as it eliminates possible disputes over whether a simple Excel spreadsheet is an adequate "database" under prior language. Marquez testimony, Tr. 5:1471:3-12. NMOGA is supportive of the Commercial Disposal Group's suggested language addition at the end of this provision.
[61] "Contemporaneously" is ambiguous and the required timeframe is specified in (8)(a) so the term should be deleted.
[62] As Ms. Kuehn testified, database development projects often take years. Kuehn testimony, Tr. 5:1370:3-8. The challenge is that NMED has not given "years" to develop the date and time stamp, which is one of the more technically challenging issues, but only 3 months. *See* proposed 20.2.50.112.A.(8)(b). Even if NMED is correct that a number of apps are available that might work, until the apps are identified and approved, they cannot be integrated into industry's database systems. Initially the Department suggested 3 months and now one year. Neither is enough time for such a large-scale integration project. Smitherman testimony, Tr. 5:1427:21-5:1428:25; Brown testimony, Tr. 5:1437:19-5:1439:11.
[63] For good cause is added consistent with the language allowing an operator to request a hearing on whether the department had good cause to request to the third party audit. Ms. Kuehn indicated that this was intended. Kuehn testimony, Tr. 5:1360:15-21.

20.2.50.111.B NMAC.

B. Monitoring requirements:

(1) Unless otherwise specified, the term monitoring as used in this Part includes, but is not limited to, monitoring, testing, or inspection requirements. Unless otherwise specified in this Part, monitoring is required to commence upon the date that the associated control requirements become effective.[64]

(2) If equipment is shut down at the time of periodic testing, monitoring, or inspection required under this Part, the owner or operator shall not be required to restart the unit for the sole purpose of performing the testing, monitoring, or inspection, but shall note the shut down in the records kept for that equipment for that monitoring event.

(3) An owner or operator may submit for the department's review and approval an equally effective, enforceable, and equivalent alternative monitoring strategy. Such requests shall be made on an application form provided by the department. The department shall issue a letter approving or denying the requested alternative monitoring strategy. An owner or operator shall comply with the default monitoring requirements in this Part and shall not operate under an alternative monitoring strategy until it has been approved by the department.[65]

(4) For each monitoring event, the owner, operator, or authorized representative shall monitor as required by the applicable sections of this Part.

C. Recordkeeping requirements:

(1) Within three business days of a monitoring event and when final reports are received, an electronic record shall be made of the monitoring event and shall include the information required by the applicable sections of this Part.

(2) The owner or operator shall keep an electronic record required by this Part for five years.

(3) By July 1 of each calendar year starting in 2024, the owner or operator shall generate a Compliance Database Report (CDR) on all assets under its control that are subject to the CDR requirements of this Part at the time the CDR is prepared and keep this report on file for five years.[66]

D. Reporting requirements: Within three business days of a request by the department, the owner or operator shall for each source subject to the request, provide the requested information by electronically submitting a CDR to the department's Secure Extranet Portal (SEP), or by other means and formats specified by the department in its request. If the department requests a CDR from multiple facilities, additional time will be given as appropriate.[67]

[20.2.50.112 NMAC - N, XX/XX/2021]

20.2.50.113 ENGINES AND TURBINES:

A. Applicability: Portable and stationary natural gas-fired spark ignition engines, compression ignition engines, and natural gas-fired combustion turbines located at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and transmission compressor stations, with a rated horsepower greater than the horsepower ratings of table 1, 2, and 3 of 20.2.50.113 NMAC are subject to the requirements of 20.2.50.113 NMAC. Non-road engines as defined in 40 C.F.R. §§ 1068.30 are not subject to 20.2.50.113 NMAC.[68]

---

[64] This is a complex rule and it is possible that NMED and NMOGA have missed a monitoring applicability date. NMOGA proposes this "general" applicability date for monitoring in case there are any sections where the start date for monitoring is not specified clearly. The proposed language corresponds to general air pollution control practice.

[65] NMED has proposed to delete this provision. NMOGA agrees it should either be broadened or deleted. As written it duplicates a provision in 20.2.50.116 NMAC and is not needed.

[66] NMOGA appreciates NMED's clarification of the annual reporting requirement. The proposed language is consistent with the concerns and recommendations made by Mr. Smitherman. Smitherman testimony, Tr. 5:1429:14-5:1430:14. *See also* Cooper testimony, Tr. 5:1492:7-5:1493:3.

[67] NMED agreed that it "will" give additional time if multiple facility CDRs are requested. Bisbey-Kuehn testimony, Tr. 1374:10-25. In addition, to the extent that Wild Earth Guardians and others believe that additional "deviation" reporting is necessary, the benefits of that reporting are unclear, and they impose significant additional costs and burdens on both NMED and industry. Copeland testimony, Tr. 5:1456:24-5:1457:23. NMOGA dislikes the requested expansion in the Department's January 18, 2022 redline because it extends beyond the CDR. If limited to the CDR, NMOGA takes no exception. If extended beyond the CDR, there is no evidentiary record to support whether such information could be produced in such a short time fram.

[68] New Mexico is preempted from regulating most aspects of non-road engines. *See* NMOGA Brief, II.F., 22-23.. Ms. Kuehn testified that NMED agreed that "nonroad engines that are regulated by the federal government are not subject to this subpart, and we agreed with that comment, that it was correct, and so we've added this clarifying language." Kuehn/Palmer testimony, Tr. 6:1682:23-6:1683:6.

B. Emission standards: [69],[70]

(1) The owner or operator of a portable or stationary natural gas-fired spark ignition engine, compression ignition engine, or natural gas-fired combustion turbine shall ensure compliance with the emission standards by the dates specified in Subsection B of 20.2.50.113 NMAC, except as otherwise specified under an Alternative Compliance Plan approved pursuant to Paragraph (10) of Subsection B of 20.2.50.113 NMAC or alternative emissions standards approved pursuant to Paragraph (11) of Subsection B of 20.2.50.113 NMAC.

(2) The owner or operator of an existing natural gas-fired spark ignition engine shall complete an inventory of all existing engines subject to this Part by January 1, 2023, and shall prepare a schedule to ensure that each existing engine does not exceed the emission standards in table 1 of Paragraph (2) of Subsection B of 20.2.50.113 NMAC as follows, except as otherwise specified under an Alternative Compliance Plan (ACP) approved pursuant to Paragraph (10) of Subsection B of 20.2.50.113 NMAC or alternative emissions standards approved pursuant to Paragraph (11) of Subsection B of 20.2.50.113 NMAC:

(a) by January 1, 2025, the owner or operator shall ensure at least thirty percent of the company's existing engines meet the emission standards.

(b) by January 1, 2027, the owner or operator shall ensure at least an additional thirty-five percent of the company's existing engines meet the emission standards.

(c) by January 1, 2029, the owner or operator shall ensure that the remaining thirty-five percent of the company's existing engines meet the emission standards.

(d) in lieu of meeting the emission standards for an existing natural gas-fired spark ignition engine, an owner or operator may reduce the annual hours of operation of an engine such that the annual PTE of NOx and VOC emissions are reduced to achieve an equivalent allowable ton per year emission reduction as set forth in table 1 of Paragraph (2) of Subsection B of 20.2.50.113 NMAC, or by at least ninety-five percent per year.

Table 1 - EMISSION STANDARDS FOR EXISTING NATURAL GAS-FIRED SPARK IGNITION ENGINES[71]

Engine Type	Rated bhp	NO_x	CO	NMNEHC (as propane)
2 Stroke Lean Burn	>1,000	3.0 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr
4-Stroke Lean Burn	>1,000 bhp and <1,775 bhp	2.0 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr
4-Stroke Lean Burn	≥1,775 bhp	0.5 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr
Rich Burn	>1,000 bhp	0.5 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr

(3) The owner or operator of a new natural gas-fired spark ignition engine shall ensure the engine does not exceed the emission standards in table 2 of Paragraph (3) of Subsection B of 20.2.50.113 NMAC

[69] Prior versions of this rule had proposed to regulate "installation" or "relocation." Ms. Kuehn testified that upon further reflection, the Department does not believe this is appropriate and that language was removed. Kuehn/Palmer testimony, Tr. 6:1686:1-6; Lisowski Rebuttal Testimony, NMOGA Exhibit 43, 1:26-2:3; 6:33-7:13.

[70] Ms. Kuehn testified that the "parties are largely in agreement with the new emission standards and thresholds that [NMED] established in this rule." Kuehn/Palmer testimony, Tr. 6:1682:10-13. She later testified that NMED had revised the tables based on some of the other state programs, such as Pennsylvania's GP-5 program, having other exemptions or off-ramps that were not recognized originally or assumed different fuel types or sizes from those in New Mexico. Kuehn/Palmer testimony, Tr. 6:1701:23-6:1702:5. Mr. Palmer also stated that the department revised the limits based on achievability and cost effectiveness based on the testimony received. Kuehn/Palmer testimony, Tr. 6:1713:6-11. Mr. Lisowski outlined the technical bases for why additional LEC is not available, Tr. 6:1725:17-6:1727:7. Mr. Lisowski also explained why certain retrofit technologies are not widely applicable, Tr. 6:1727:11-6:1728:1, limitations of NSCR in the field due to drift and fuel gas variation, Tr. 6:1729:13-6:1730:8, and why SCR is generally not effective for oilfield engines, Tr. 6:1730:9-6:1731:9. Mr. Lisowski's comments were echoed by Mr. Sheldon, Tr. 6:1748:7-6:1749:18, and Mr. Dutton, Tr. 6:1753:15-6:1755:3, both experts introduced by the Gas Compressor Association. Ms. Devore and Dr. Orozco argued that the 2.0 g/bhp-hr should be reduced to 1.2 g/bhp-hr, but Mr. Lisowski testified that this was not achievable as a blanket matter and that "there's going to be a large subset of engines in New Mexico that cannot achieve that target and will need to be replaced." Lisowski, Tr. 9:2993:13-18. Mr. Lisowski also explained why, practically, a lower limit was not achievable even with some engines meeting NSPS in response to a question from Chair Suina. Tr. 9:2999:25-9:3001:11

[71] Ms. Kuehn testified that the Table 1 limits are based on the testimony of the parties who filed direct and rebuttal testimony. Kuehn/Palmer testimony, Tr. 6:1685:20-25. Mr. Lisowski testified extensively as to why the limits were appropriate. A succinct summary is found in Lisowksi Rebuttal Testimony, NMOGA Exhibit 43.

upon startup.

Table 2 - EMISSION STANDARDS FOR NEW NATURAL GAS-FIRED SPARK IGNITION ENGINES[72]

Engine Type	Rated bhp	NO_x	CO	NMNEHC (as propane)
Lean-burn	> 500 and < 1875	0.50 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr
Lean-burn	≥ 1875	0.30 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr
Rich-burn	>500	0.50 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr

(4) The owner or operator of a natural gas-fired spark ignition engine with NO_x emission control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less, corrected to fifteen percent oxygen.

(5) The owner or operator of a compression ignition engine shall ensure compliance with the following emission standards:

(a) a new portable or stationary compression ignition engine with a maximum design power output equal to or greater than 500 horsepower that is not subject to the emission standards under Subparagraph (b) of Paragraph (5) of Subsection B of 20.2.50.113 NMAC shall limit NO_x emissions to not more than nine g/bhp-hr upon startup.

(b) a stationary compression ignition engine that is subject to and complying with Subpart IIII of 40 CFR Part 60, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, is not subject to the requirements of Subparagraph (a) of Paragraph (5) of Subsection B of 20.2.50.113 NMAC.[73]

(6) The owner or operator of a portable or stationary compression ignition engine with NO_x emission control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less, corrected to fifteen percent oxygen.

(7) The owner or operator of a stationary natural gas-fired combustion turbine with a maximum design rating equal to or greater than 1,000 bhp shall comply with the applicable emission standards for an existing, new, or reconstructed turbine listed in table 3 of Paragraph (7) of Subsection B of 20.2.50.113 NMAC.

(a) The owner or operator of an existing stationary natural gas-fired combustion turbine shall complete an inventory of all existing turbines subject to Part 50 by July 1, 2023, and shall prepare a schedule to ensure that each subject existing turbine does not exceed the emission standards in table 3 of Paragraph (7) of Subsection B of 20.2.50.113 NMAC as follows, except as otherwise specified under an Alternative Compliance Plan approved pursuant to Paragraph (10) of Subsection B of 20.2.50.113 NMAC or alternative emissions standards approved pursuant to Paragraph (11) of Subsection B of 20.2.50.113 NMAC:

(i) by January 1, 2024, the owner or operator shall ensure at least thirty percent of the company's existing turbines meet the emission standards.

(ii) by January 1, 2026, the owner or operator shall ensure at least an additional thirty-five percent of the company's existing turbines meet the emission standards.

(iii) by January 1, 2028, the owner or operator shall ensure that the remaining thirty-five percent of the company's existing turbines meet the emission standards.

(iv) in lieu of meeting the emission standards for an existing stationary natural gas-fired combustion turbine, an owner or operator may reduce the annual hours of operation of a turbine such that the annual PTE of NOx and VOC emissions are reduced to achieve an equivalent allowable ton per year emission reduction as set forth in table 3 of Paragraph (7) of Subsection B of 20.2.50.113 NMAC, or by at least ninety-five percent per year.

---

[72] Ms. Kuehn testified that these limits were set based upon Ohio precedent and the compelling testimony of industry stakeholders. Kuehn/Palmer testimony, Tr. 6:1868:9-22. Mr. Lisowski testified extensively as to why the limits were appropriate. A succinct summary is found in Lisowksi Rebuttal Testimony, NMOGA Exhibit 43.
Mr. Brindley, Ms. Nolting and Mr. Trent also testified extensively in support of the final levels on behalf of Kinder Morgan. Tr. 6:1807:4-6:1814:8. Ms. Devore expressed some concern about the removal of "install" and whether this created enforceability issues, but upon further consideration agreed that the removal did not create a gap in the regulations. Tr. 8:2401:9-8:2402:2.
[73] Kuehn/Palmer testimony, Tr. 6:1687:6-17.

Table 3 - EMISSION STANDARDS FOR STATIONARY COMBUSTION TURBINES[74]

For each applicable existing natural gas-fired combustion turbine, the owner or operator shall ensure the turbine does not exceed the following emission standards no later than the schedule set forth in Paragraph (7)(a) of Subsection B of 20.2.50.113 NMAC:			
Turbine Rating (bhp)	NO_x (ppmvd @15% O_2)	CO (ppmvd @ 15% O_2)	NMNEHC (as propane, ppmvd @15% O_2)
≥1,000 and <4,100	150	50	9
≥4,100 and <15,000	50	50	9
≥15,000	50	50 or 93% reduction	5 or 50% reduction
For each applicable new natural gas-fired combustion turbine, the owner or operator shall ensure the turbine does not exceed the following emission standards upon startup:			
Turbine Rating (bhp)	NO_x (ppmvd @15% O_2)	CO (ppmvd @ 15% O_2)	NMNEHC (as propane, ppmvd @15% O_2)
≥1,000 and <4,000	100	25	9
≥4,000 and <15,900	15	10	9
≥15,900	9.0 Uncontrolled or 2.0 with Control	10 Uncontrolled or 1.8 with Control	5

(8) The owner or operator of a stationary natural gas-fired combustion turbine with NO_x emission control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less, corrected to fifteen percent oxygen.

(9) The owner or operator of an emergency use engine as defined by 40 C.F.R. §§ 60.4211, 60.4243, or 63.6675 is not subject to the emissions standards in this Part but shall be equipped with a non-resettable hour meter to monitor and record any hours of operation.

(10) In lieu of complying with the emission standards for individual engines and turbines established in Subsection B of 20.2.50.113 NMAC, an owner or operator may elect to comply with the emission standards through an Alternative Compliance Plan (ACP) approved by the department. An ACP must include the list of engines or turbines subject to the ACP, and a demonstration that the total allowable emissions for the engines or turbines subject to the ACP will not exceed the total allowable emissions under the emission standards of this Part. Prior to submitting a proposed ACP to the Department, the owner or operator shall comply with the following requirements in the order listed:

(a) The owner or operator shall contract with an independent third-party engineering or consulting firm to conduct a technical and regulatory review of the ACP proposal. The selected firm shall review the proposal to determine if it meets the requirements of this Part, and shall prepare and certify an evaluation of the proposed ACP indicting whether the ACP proposal adheres to the requirements of this Part.

(b) Following the independent third-party review, the owner or operator shall provide the ACP, along with the third-party evaluation and findings, to the department for posting on the department's website. The department shall post the ACP and the third-party review within 15 days of receipt.

(c) Following posting by the department, the owner or operator shall publish a notice in a newspaper of general circulation announcing the ACP proposal, the dates it will be available for review and comment by the public, and information on how and where to submit comments. The dates specified in the public notice must provide for a thirty-day comment period.

(d) Following the close of the thirty-day notice and comment period, the department shall send the comments submitted on the ACP proposal and findings to the owner or operator. The owner or operator shall provide written responses to all comments to the department.

[74] Ms. Kuehn testified that these limits were derived based on research and comments from manufacturers. Kuehn/Palmer testimony, Tr. 6:1689:4-6:1690:3. Ms. Witherspoon, representing Solar Turbines, testified that the Department's September 16, 2021, table, if corrected to 4,100 bhp for existing turbines, was appropriate and achievable. Tr. 10:3374:6-25.

(e) Following receipt of the owner or operator's responses to comments received during the thirty-day comment period, the department shall make a determination whether to approve or deny the ACP proposal within 90 days. The department shall approve an ACP that meets the requirements of this Part, unless the department determines that the total allowable emissions under the ACP exceed the total allowable emissions under the emission standards of 20.2.50.113 NMAC. If approved by the department, the emission reductions and associated emission limits for the affected engines or turbines shall become enforceable terms under this Part.[75]

(11) The owner or operator may submit a request for alternative emission standards for a specific engine or turbine based on technical impracticability or economic infeasibility. The owner or operator is not required to submit an ACP proposal under Paragraph (10) of Subsection B of 20.2.50.113 NMAC prior to submission of a request for alternative emissions standards under this Paragraph (11), provided that the owner or operator satisfies Subparagraph (b) of Paragraph (11) of Subsection B of 20.2.50.113 NMAC, below. To qualify for an alternative emission standard, an owner or operator must comply with the following requirements:

(a) prepare a reasonable demonstration detailing why it is not technically practicable or economically feasible for the individual engine or turbine to achieve the emissions standards in table 1 of Paragraph (2) of Subsection B of 20.2.50.113 NMAC or table 3 of Paragraph (7) of Subsection B of 20.2.50.113 NMAC, as applicable;

(b) prepare a demonstration detailing why emissions from the individual engine or turbine cannot be addressed through an ACP in a technically practicable or economically feasible manner;

(c) prepare a technical analysis for the affected engine or turbine specifying the emission reductions that can be achieved through other means, such as combustion modifications or capacity limitations. The technical analysis shall include an analysis of any previous modifications of the source and a determination whether such modifications meet the definition of a reconstructed source, such that the source should be considered a new source under federal regulations. The analysis shall include a certification that the modifications to the source are not in violation of any state or federal air quality regulation; and

(d) fulfill the requirements of Subparagraphs (a) through (c) of Paragraph (10) of Subsection B of 20.2.50.113 NMAC.

(e) Following the close of the thirty-day notice and comment period, the department shall send the comments submitted on the alternative emission standards and findings to the owner or operator. The owner or operator shall provide written responses to all comments to the department.

(f) Following receipt of the owner or operator's responses to comments received during the thirty-day comment period, the department shall make a determination whether to approve or deny the alternative emission standards within 90 days. If approved by the department, the emission reductions and alternative emission standards for the affected engine or turbine shall become enforceable terms under this Part.

(g) If approved by the department, the emissions reductions and alternative standards for the affected engine or turbine shall become enforceable terms under this Part.[76]

(12) A short-term replacement engine may be substituted for any engine subject to Section 20.2.50.113 NMAC consistent with any applicable air quality permit containing allowances for short term replacement engines, including but not limited to New Source Review and General Construction Permits issued under 20.2.72 NMAC. A short-term engine replacement is not considered a "new" engine for purposes of this Part unless the engine it replaces is a "new" engine within the meaning of this Part. The reinstallation of the existing engine following removal of the short-term replacement engine is not considered a "new" engine under this Part unless the engine was "new" prior to the temporary replacement.

C. Monitoring requirements:[77]

(1) Maintenance and repair for a spark ignition engine, compression ignition engine, and stationary combustion turbine shall meet the manufacturer recommended maintenance schedule as defined in 20.2.50.112 NMAC.

(2) Maintenance conducted consistent with an applicable NSPS or NESHAP requirement shall be deemed to be in compliance with 20.2.50.113.C(1) NMAC.

(3) Catalytic converters (oxidative, selective, and non-selective) and AFR controllers shall be

[75] Ms. Kuehn explained the desirability and steps to ensure accountability and transparency for this compliance provision. Kuehn/Palmer testimony, Tr. 6:1679:11-6:1682:5; 6:1690:23-6:1693:4.
[76] Ms. Kuehn explained the desirability and steps to ensure accountability and transparency for this compliance provision. Kuehn/Palmer testimony, Tr. 6:1679:11-6:1682:5; 6:1690:23-6:1693:4.
[77] Ms. Kuehn testified as to the need and application of the monitoring requirements. Kuehn/Palmer testimony, Tr. 6:1694:1-6:1697:7.

inspected and maintained according to manufacturer specifications as defined in 20.2.50.112 NMAC, and shall include replacement of oxygen sensors as necessary for oxygen-based controllers. During periods of catalytic converter or AFR controller maintenance, the owner or operator shall shut down the engine or turbine until the catalytic converter or AFR controller can be replaced with a functionally equivalent spare to allow the engine or turbine to return to operation.

(4) For equipment operated for 500 hours per year or more, compliance with the emission standards in Subsection B of 20.2.50.113 NMAC shall be demonstrated within 180 days of the effective date applicable to the source as defined by Subsection B(2) and (7) or, if installed more than 180 days after the effective date, within 60 days after achieving the maximum production rate at which the source will be operated, but not later than 180 days after initial startup of such source.[78] Compliance with the applicable emission standards shall be demonstrated by performing an initial emission test for NOx and VOC, as defined in 40 CFR 51.100(s) using U.S. EPA reference methods or ASTM D6348. Periodic monitoring shall be conducted annually to demonstrate compliance with the allowable emission standards and may be demonstrated utilizing a portable analyzer or EPA reference methods. For units with g/hp-hr emission standards, the engine load shall be calculated using the following equations:

$$\text{Load (Hp)} = \frac{\text{Fuel consumption (scf/hr) x Measured fuel heating value (LHV btu/scf)}}{\text{Manufacturer's rated BSFC (btu/bhp-hr) at 100\% load or best efficiency}}$$

$$\text{Load (Hp)} = \frac{\text{Fuel consumption (gal/hr) x Measured fuel heating value (LHV btu/gal)}}{\text{Manufacturer's rated BSFC (btu/bhp-hr) at 100\% load or best efficiency}}$$

Where: LVH = lower heating value, btu/scf, or btu/gal, as appropriate; and
BSFC = brake specific fuel consumption

If the manufacturer's rated BSFC is not available, an operator may use an alternative load calculation methodology based on available data.

(a) emissions testing events shall be conducted within 10 percent of 100 percent peak (or the highest achievable) load. The load and the parameters used to calculate it shall be recorded to document operating conditions at the time of testing and shall be included with the test report.

(b) emissions testing utilizing a portable analyzer shall be conducted in accordance with the requirements of the current version of ASTM D6522. If a portable analyzer has met a previously approved department criterion, the analyzer may be operated in accordance with that criterion until it is replaced.

(c) the default time period for a test run shall be at least 20 minutes.

(d) an emissions test shall consist of three separate runs, with the arithmetic mean of the results from the three runs used to determine compliance with the applicable emission standard.

(e) during emissions tests, pollutant and diluent concentration shall be monitored and recorded. Fuel flow rate shall be monitored and recorded if stack gas flow rate is determined utilizing U.S. EPA reference method 19. This information shall be included with the periodic test report.

(f) stack gas flow rate shall be calculated in accordance with U.S. EPA reference method 19 utilizing fuel flow rate (scf) determined by a dedicated fuel flow meter and fuel heating value (Btu/scf). The owner or operator shall provide a contemporaneous fuel gas analysis (preferably on the day of the test, but no earlier than three months before the test date) and a recent fuel flow meter calibration certificate (within the most recent quarter) with the final test report. Alternatively, stack gas flow rate may be determined by using U.S. EPA reference methods 1 through 4 or through the use of manufacturer provided fuel consumption rates.

(g) upon request by the department, an owner or operator shall submit a notification and protocol for an initial or annual emissions test.

(h) emissions testing shall be conducted at least once per 8760 hours of operation or three calendar years, whichever comes first[79]. Emission testing required by Subparts GG, IIII, JJJJ, or KKKK of 40 CFR 60, or Subpart ZZZZ of 40 CFR 63, may be used to satisfy the emissions testing requirements if it meets the

[78] Timing for emissions testing consistent with testing for units subject to New Source Performance standards under 40 C.F.R. 60.8(a).

[79] Commercial disposal group requested change to 8760 hours or 3 years. NMOGA agrees with this change for non-emergency engines but not for emergency engines, which by definition should have fewer than 300 hours of operation in three years. Emergency engines should be left at 8760 hours.

requirements of 20.2.50.113 NMAC and is completed at least once per calendar year.

(i) The results of emissions testing demonstrating compliance with the emission standard for CO may be used as a surrogate to demonstrate compliance with the emission standard for NMNEHC.

(5) The owner or operator of equipment operated less than 500 hours per year shall monitor the hours of operation using a non-resettable hour meter and shall test the unit at least once per 8760 hours of operation in accordance with the emissions testing requirements in Paragraph (4) of Subsection C of 20.2.50.113 NMAC.

(6) An owner or operator of an emergency use engine as defined by 40 C.F.R. §§ 60.4211, 60.4243, or 63.6675 shall monitor the hours of operation by a non-resettable hour meter.

(7) An owner or operator limiting the annual operating hours of an engine or turbine to meet the requirements of Paragraph (2) or (7) of Subsection B of 20.2.50.113 NMAC shall monitor the hours of operation by a non-resettable hour meter.

(8) Prior to any monitoring, testing, inspection, or maintenance of an engine or turbine, the owner or operator shall date and time stamp the event, and the monitoring data entry shall be made in accordance with the requirements of 20.2.50.112 and 113 NMAC.

D. Recordkeeping requirements:[80]

(1) The owner or operator of a spark ignition engine, compression ignition engine, or stationary combustion turbine shall maintain a record in accordance with 20.2.50.112 NMAC for the engine or turbine. The record shall include:

(a) the make, model, serial number, and unique identification number for the engine or turbine;

(b) location of the source (latitude and longitude);

(c) a copy of the engine, turbine, or control device manufacturer recommended maintenance and repair schedule as defined in 20.2.50.112 NMAC; and

(d) all inspection, maintenance, or repair activity on the engine, turbine, and control device, including:

(i) the date and time stamp(s), including GPS of the location, of an inspection, maintenance, or repair;

(ii) the date a subsequent analysis was performed (if applicable);

(iii) the name of the person(s) conducting the inspection, maintenance or repair;

(iv) a description of the physical condition of the equipment as found during the inspection;

(v) a description of maintenance or repair conducted; and

(vi) the results of the inspection and any required corrective actions.

(2) The owner or operator of a spark ignition engine, compression ignition engine, or stationary combustion turbine shall maintain records of initial and annual emissions testing for the engine or turbine for a period of five years. The records shall include:

(a) make, model, and serial number for the tested engine or turbine;

(b) the date and time stamp(s), including GPS of the location, of any monitoring event, including sampling or measurements;

(c) date analyses were performed;

(d) name of the person(s) and the qualified entity that performed the analyses;

(e) analytical or test methods used;

(f) results of analyses or tests;

(g) calculated emissions of NOx and VOC in lb/hr and tpy; and

(h) operating conditions at the time of sampling or measurement.

(3) The owner or operator of an emergency use engine as defined by 40 C.F.R. §§ 60.4211, 60.4243, or 63.6675 shall record the total annual hours of operation as recorded by the non-resettable hour meter.

(4) The owner or operator limiting the annual operating hours of an engine or turbine to meet the requirements of Paragraph (2) or (7) of Subsection B of 20.2.50.113 NMAC shall record the hours of operation by a non-resettable hour meter. The owner or operator shall calculate and record the annual NOx and VOC emission calculation, based on the engine or turbine's actual hours of operation, to demonstrate that an equivalent allowable

[80] Ms. Kuehn testified as to the need for the various recordkeeping requirements and adjustments made in response to industry and other comments. Tr. 6:1697:8-13.

ton per year emission reduction as set forth in table 1 or table 3 of Paragraph (2) or (7) of Subsection B of 20.2.50.113 NMAC, or the ninety-five percent emission reduction requirement is met.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.113 NM–C - N, XX/XX/2021]

20.2.50.114 COMPRESSOR SEALS:

A. Applicability:

(1) Centrifugal compressors using wet seals and located at tank batteries, gathering and boosting stations, and natural gas processing plants are subject to the requirements of 20.2.50.114 NMAC. Centrifugal compressors located at well sites and transmission compressor stations are not subject to the requirements of 20.2.50.114 NMAC.

(2) Reciprocating compressors located at tank batteries, gathering and boosting stations, and natural gas processing plants are subject to the requirements of 20.2.50.114 NMAC. Reciprocating compressors located at well sites and transmission compressor stations are not subject to the requirements of 20.2.50.114 NMAC.

B. Emission standards:

(1) The owner or operator of an existing centrifugal compressor with wet seals shall control VOC emissions from a centrifugal compressor wet seal fluid degassing system by at least ninety-five percent within two years of the effective date of this Part. Emissions shall be captured and routed via a closed vent system to a control device, recovery system, fuel cell, or a process stream.[81]

(2) The owner or operator of an existing reciprocating compressor shall, either:

(a) replace the reciprocating compressor rod packing after every 26,000 hours of compressor operation or every 36 months, whichever is reached later. The owner or operator shall begin counting the hours of compressor operation toward the first replacement of the rod packing upon the effective date of this Part; or[82]

(b) beginning no later than two years from the effective date of this Part, collect emissions from the rod packing, and route them via a closed vent system to a control device, recovery system, fuel cell, or a process stream.

(3) The owner or operator of a new centrifugal compressor with wet seals shall control VOC emissions from the centrifugal compressor wet seal fluid degassing system by at least ninety-five percent upon startup. Emissions shall be captured and routed via a closed vent system to a control device, recovery system, fuel cell, or process stream.

(4) The owner or operator of a new reciprocating compressor shall, upon startup, either:

(a) replace the reciprocating compressor rod packing after every 26,000 hours of compressor operation, or every 36 months, whichever is reached later; or

(b) collect emissions from the rod packing and route them via a closed vent system to a control device, a recovery system, fuel cell, or a process stream.

(5) The owner or operator complying with the emission standards in Subsection B of 20.2.50.114 NMAC through use of a control device shall comply with the control device requirements in 20.2.50.115 NMAC.

C. Monitoring requirements:

(1) The owner or operator of a centrifugal compressor complying with Paragraph (1) or (3) of Subsection B of 20.2.50.114 NMAC shall maintain a closed vent system encompassing the wet seal fluid degassing system that complies with the monitoring requirements in 20.2.50.115 NMAC.

[81] NMED proposed deleting this provision in its January 18, 2022 redline. NMOGA has no objection to its deletion as it eliminates a safety/quality issue. Lisowski Rebuttal Testimony, NMOGA Exhibit 43, 12:11-17.

[82] Kuehn/Palmer testimony, NMED Exhibit 32:60:6-12. VOC emissions from reciprocating compressor rod packing can be minimized by replacing the rod packing on a regular basis before it becomes excessively worn.; Lisowski testimony, Exhibit A3:132-133. Mr. Lisowski testified that operators elect to replace reciprocating compressor rod packing at the specified time or hour interval, which makes the rule irrelevant. Removing the requirement to "collect compressor vents under negative pressure" allows operators to determine the most effective method for reducing venting.; Lisowski rebuttal testimony, Exhibit A3:12:4-17. Mr. Lisowski testified that when negative pressure is used as a control system you have the potential to introduce oxygen which can be a safety issue as well as an issue for meeting gas specs to midstream providers (for upstream producers). *See also* Tr. 6:1859.; Smitherman testimony, NMOGA Exhibit A1:21:1-12. Mr. Smitherman testified that compressor seals are a very small source of ozone precursor emissions. If the section is not eliminated, he supports the option of collecting the small gas volumes, without negative pressures being applied, in order to route them to a control device.

(2) The owner or operator of a reciprocating compressor complying with Subparagraph (a) of Paragraph (2) or Subparagraph (a) of Paragraph (4) of Subsection B of 20.2.50.114 NMAC shall continuously monitor the hours of operation with a non-resettable hour meter and track the number of hours since initial startup or since the previous reciprocating compressor rod packing replacement.[83]

(3) The owner or operator of a reciprocating compressor complying with Subparagraph (b) of Paragraph (2) or Subparagraph (b) of Paragraph (4) of Subsection B of 20.2.50.114 NMAC shall monitor the rod packing emissions collection system semiannually to ensure that it operates as designed and routes emissions through a closed vent system to a control device, recovery system, fuel cell, or process stream.

(4) The owner or operator of a centrifugal or reciprocating compressor complying with the requirements in Subsection B of 20.2.50.114 NMAC through use of a closed vent system or control device shall comply with the monitoring requirements in 20.2.50.115 NMAC.

(5) The owner or operator of a centrifugal or reciprocating compressor shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. **Recordkeeping requirements:**

(1) The owner or operator of a centrifugal compressor using a wet seal fluid degassing system shall maintain a record of the following:

(a) the location (latitude and longitude) of the centrifugal compressor;

(b) the date of construction, reconstruction, or modification of the centrifugal compressor;

(c) the monitoring required in Subsection C of 20.2.50.114 NMAC, including the time and date of the monitoring, the person(s) conducting the monitoring, a description of any problem observed during the monitoring, and a description of any corrective action taken; and

(d) the type, make, model, and unique identification number or equivalent identifier of a control device used to comply with the control requirements in Subsection B of 20.2.50.114 NMAC.

(2) The owner or operator of a reciprocating compressor shall maintain a record of the following:

(a) the location (latitude and longitude) of the reciprocating compressor;

(b) the date of construction, reconstruction, [84]of the reciprocating compressor; and

(c) the monitoring required in Subsection C of 20.2.50.114 NMAC, including:

(i) the number of hours of operation since the effective date, initial startup after the effective date, or the last rod packing replacement, as applicable;

(ii) data showing the effectiveness of the rod packing emissions collection system, as applicable; and

(iii) the time and date of the inspection, the person(s) conducting the inspection, a description of any problems observed during the inspection, and a description of corrective actions taken.

(3) The owner or operator of a centrifugal or reciprocating compressor complying with the requirements in Subsection B of 20.2.50.114 NMAC through use of a control device or closed vent system shall comply with the recordkeeping requirements in 20.2.50.115 NMAC.

(4) The owner or operator of a centrifugal or reciprocating compressor shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. **Reporting requirements:** The owner or operator of a centrifugal or reciprocating compressor shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.114 NM–C - N, XX/XX/2021]

20.2.50.115 CONTROL DEVICES AND CLOSED VENT SYSTEMS:

A. **Applicability:** These requirements apply to control devices and closed vent systems as defined in 20.2.50.7 NMAC and used to comply with the emission standards and emission reduction requirements in this Part.

B. **General requirements:**

(1) Control devices used to demonstrate compliance with this Part shall be installed, operated, and maintained consistent with manufacturer specifications, and good engineering and maintenance

[83] Lisowski rebuttal testimony NMOGA Exhibit 43:12:18-21. Mr. Lisowski testified that it is not an issue to install non-resettable meters on compressors and is already used by most operators.

[84] "Modification" as a concept is not being used in this rule and has no defined meaning. Its inclusion was inadvertently overlooked here and should be deleted.

practices.

(2) Control devices shall be adequately designed and sized to achieve the control efficiency rates required by this Part and to handle the reasonably expected range of inlet VOC or NOx concentrations or volumes.

(3) The owner or operator shall inspect control devices visually or consistent with applicable federally approved inspection methods at least monthly to identify defects, leaks, and releases, and to ensure proper operation. Prior to an inspection or monitoring event, the owner or operator shall date and time stamp the event, and the required monitoring data entry shall be made in accordance with this Part.

(4) The owner or operator shall ensure that a control device used to comply with emission standards in this Part operates as a closed vent system that captures and routes VOC emissions to the control device, in order to minimize venting of unburnt gas to the atmosphere.

(5) The owner or operator of a permanent closed vent system for a centrifugal compressor wet seal fluid degassing system, reciprocating compressor, natural gas driven pneumatic pump, or storage vessel using a control device or routing emissions to a process shall:

(a) ensure the control device or process is of sufficient design and capacity to accommodate the expected range of emissions from the affected sources;

(b) conduct an assessment to confirm that the closed vent system is of sufficient design and capacity to ensure that emissions from the affected equipment are routed to the control device or process; and

(c) have the assessment certified by a qualified professional engineer or an in-house engineer with expertise regarding the design and operation of closed vent system(s) in accordance with Paragraphs (c)(i) and (ii) of this Section.

(i) The assessment of the closed vent system shall be prepared under the direction or supervision of a qualified professional engineer or an in-house engineer who signs the certification in Paragraph (c)(ii) of this Section.

(ii) the owner or operator shall provide the following certification, signed and dated by a qualified professional engineer or an in-house engineer: "I certify that the closed vent system assessment was prepared under my direction or supervision. I further certify that the closed vent system assessment was conducted, and this report was prepared, pursuant to the requirements of this Part. Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete."

(d) an owner or operator of an existing closed vent system shall comply with the requirements of Paragraph (5) of Subsection B of 20.2.50.115 NMAC within three years of the effective date of this Part and within 90 days of startup for a new closed vent system.

(6) The owner or operator shall keep manufacturer specifications for all control devices on file. The information shall include the unique identification number, type of unit, manufacturer name, make, model, capacity, and destruction or reduction efficiency data.

C. Requirements for open flares:

(1) Emission standards:

(a) the flare shall be properly sized and designed to ensure proper combustion efficiency to combust the gas sent to the flare, and combustion shall be maintained for the duration of time that sufficient[85] gas is sent to the flare. The owner or operator shall not send gas to the flare in excess of the manufacturer maximum rated capacity. Failure to combust during the auto-igniter reignition cycle is not a violation of this requirement.[86]

(b) the owner or operator shall equip each new and existing flare (except those flares required to meet the requirements of Paragraph (c) of this Subsection) with a continuous pilot flame, an operational auto-igniter, or require manual ignition, and shall comply with the following no later than one year after the effective date of this part, unless otherwise specified:

(i) a flare with a continuous pilot flame or an auto-igniter shall be equipped with a system to ensure the flare is operated with a flame present at all times when gas is being sent to the

[85] There is not sufficient gas at the end of an event to sustain combustion. That should not be a violation.
[86] By definition, there will be a period between the "sparks" generated by the autoigniter and some gas could be emitted in those periods. This language clarifies that this period is not a violation.

flare. Failure of the flare to be lit prior to the auto-igniter reignition cycle is not a violation of this requirement.[87]

(ii) the owner or operator of a flare with manual ignition shall inspect and ensure a flame is present upon initiating a flaring event.

(iii) a new flare controlling a continuous waste[88] gas stream shall be equipped with a continuous pilot flame upon startup.

(iv) an existing flare controlling a continuous waste[89] gas stream shall be equipped with a continuous pilot.

(c) an existing flare located at a site with an annual average daily production of equal to or less than 10 barrels of oil per day or an average daily production of 60,000 standard cubic feet of natural gas shall be equipped with an auto-ignitor, continuous pilot, or technology (e.g. alarm) that alerts the owner or operator of a flare malfunction, if replaced or reconstructed after the effective date of this Part.

(d) the owner or operator shall operate a flare with no visible emissions, except for periods not to exceed a total of 30 seconds during any 15 consecutive minutes. The flare shall be designed so that an observer can, by means of visual observation from the outside of the flare or by other means such as a continuous monitoring device, determine whether it is operating properly. The observation may be terminated if visible emissions are observed and recorded and action is taken to address the visible emissions.

(e) the owner or operator shall repair the flare within three business days of any thermocouple or other flame detection device alarm activation.

(2) Monitoring requirements:

(a) the owner or operator of a flare with a continuous pilot or auto-igniter shall continuously monitor the presence of a pilot flame, or presence of flame during flaring if using an auto-igniter, using a thermocouple equipped with a continuous recorder and alarm to detect the presence of a flame. An alternative equivalent technology alerting the owner or operator of failure of ignition of the gas stream may be used in lieu of a continuous recorder and alarm, if approved by the department;

(b) the owner or operator of a manually ignited flare shall monitor the presence of a flame using continuous visual observation during a flaring event;

(c) the owner or operator shall, at least quarterly, and upon observing visible emissions, perform a U.S. EPA method 22 observation while the flare pilot or auto-igniter flame is present to certify compliance with visible emission requirements. The observation period shall be a minimum of 15 consecutive minutes. The observation may be terminated if visible emissions are observed and recorded and action is taken to address the visible emissions;

(d) prior to an inspection or monitoring event, the owner or operator shall date and time stamp the event, and the required monitoring data entry shall be made in accordance with this Part; and

(e) the owner or operator shall monitor the technology that alerts the owner or operator of a flare malfunction and any instances of technology or alarm activation.

(3) Recordkeeping requirements: The owner or operator of an open flare shall keep a record of the following:

(a) any instance of thermocouple or other approved technology or flame detection device alarm activation, including the date and cause of alarm activation, action taken to bring the flare into a normal operating condition, the name of the person(s) conducting the inspection, and any maintenance activity performed;

(b) the results of the U.S. EPA method 22 observations;

(c) the monitoring of the presence of a flame on a manual flare during a flaring event as required under Subparagraph (b) of Paragraph (2) of Subsection C of 20.2.50.115 NMAC;

(d) the results of the most recent gas analysis for the gas being flared, including VOC content and heating value, if any[90]; and

(e) the data and time stamp(s), including GPS of the location, of any monitoring event.

[91]

---

[87] By definition, there will be a period between the “sparks” generated by the autoigniter and some gas could be emitted in those periods. This language clarifies that this period is not a violation.

[88] Clarification added so that it is clear the pilot fuel is not a continuous gas stream implicating this requirement.

[89] Clarification added so that it is clear the pilot fuel is not a continuous gas stream implicating this requirement.

[90] At midstream facilities, there may not be a gas analysis because many facilities are combined prior to flaring.

[91] This language appears in Subsection G.

D. Requirements for enclosed combustion devices (ECD) and thermal oxidizers (TO):

(1) Emission standards:

(a) the ECD/TO shall be properly sized and designed to ensure proper combustion efficiency to combust the gas sent to the ECD/TO. The owner or operator shall not send gas to the ECD/TO in excess of the manufacturer maximum rated capacity.

(b) the owner or operator shall equip each new ECD/TO with a continuous pilot flame or an auto-igniter upon startup. Existing ECD/TO shall be equipped with a continuous pilot flame or an auto-igniter no later than two years after the effective date of this Part.

(c) ECD/TO with a continuous pilot flame or an auto-igniter shall be equipped with a system to ensure that the ECD/TO is operated with a flame present at all times when gas is sent to the ECD/TO. Combustion shall be maintained for the duration of time that gas is sent to the ECD/TO. New ECD/TOs shall comply with this requirement upon startup, and existing ECD/TOs shall comply with this requirement within 2 years of the effective date of this Part.

(d) the owner or operator shall operate an ECD/TO with no visible emissions, except for periods not to exceed a total of 30 seconds during any 15 consecutive minutes. The ECD/TO shall be designed so that an observer can, by means of visual observation from the outside of the ECD/TO or by other means such as a continuous monitoring device, determine whether it is operating properly. The observation may be terminated if visible emissions are observed and recorded and action is taken to address the visible emissions.

(2) Monitoring requirements:

(a) the owner or operator of an ECD/TO with a continuous pilot or an auto-igniter shall continuously monitor the presence of a pilot flame, or of a flame during combustion if using an auto-igniter, using a thermocouple equipped with a continuous recorder and alarm to detect the presence of a flame. An alternative equivalent technology alerting the owner or operator of failure of ignition of the gas stream may be used in lieu of a continuous recorder and alarm, if approved by the department.

(b) the owner or operator shall, at least quarterly, and upon observing visible emissions, perform a U.S. EPA method 22 observation while the ECD/TO pilot flame or auto-igniter flame is present to certify compliance with the visible emission requirements. The period of observation shall be a minimum of 15 consecutive minutes. The observation may be terminated if visible emissions are observed and recorded and action is taken to address the visible emissions.

(c) prior to an inspection or monitoring event, the owner or operator shall date and time stamp the event, and the required monitoring data entry shall be made in accordance with the monitoring requirements of this Part.

(3) Recordkeeping requirements: The owner or operator of an ECD/TO shall keep records of the following:

(a) any instance of a thermocouple or other approved technology or flame detection device alarm activation, including the date and cause of the activation, any action taken to bring the ECD/TO into normal operating condition, the name of the person(s) conducting the inspection, and any maintenance activities performed;

(b) the results of the U.S. EPA method 22 observations;

(c) the data and time stamp(s), including GPS of the location, of any monitoring event; and

(d) the results of the most recent gas analysis for the gas being combusted, including VOC content and heating value, if any [92].

[93]

E. Requirements for vapor recover units (VRU):

(1) Emission standards:

(a) the owner or operator shall operate the VRU as a closed vent system that captures and routes [94]VOC emissions directly back to the process or to a sales pipeline and does not vent to the atmosphere.

[92] Midstream facilities receive gas from multiple facilities and may not have a traditional gas analysis.
[93] This language appears in Subsection G.
[94] It is impossible to prevent all VOC emissions such as during maintenance or VOCs that cannot be captured. Meyer rebuttal testimony, NMOGA Exhibit 42:2:18-27.

(b) Except during a facility-wide upset,[95] the owner or operator shall control VOC emissions during startup, shutdown, maintenance, or other VRU downtime with a backup control device (e.g. flare, ECD, TO) or redundant VRU during the period of VRU downtime, unless otherwise approved in an air permit issued prior to the effective date of this Part.[96] Alternatively, the owner or operator may shut down and isolate the source being controlled by the VRU. For sites that already have a VRU installed as of the effective date of this Part, the owner or operator shall install backup control devices or redundant VRUs within three years of the effective date of this Part.

(2) Monitoring Requirements:

(a) the owner or operator shall comply with the standards for equipment leaks in 20.2.50.116 NMAC, or alternatively, shall implement a program that meets the requirements of Subpart OOOOa of 40 CFR 60.

(b) prior to a VRU inspection or monitoring event, the owner or operator shall date and time stamp the event, and the required monitoring data entry shall be made in accordance with the requirements of this Part.

(3) Recordkeeping requirements: For a VRU inspection or monitoring event, the owner or operator shall record the result of the event, including the name of the person(s) conducting the inspection, any maintenance or repair activities required, and the date and time stamp(s), including GPS of the location, of any monitoring event. The owner or operator shall record the type of redundant control device used during VRU downtime, or keep records of the source shut down and isolated and the time period during which it was shut down, or records of compliance with an air permit issued prior to the effective date of this Part.

[97] **F. Recordkeeping requirements:** The owner or operator of a control device or closed vent system shall maintain a record of the following:

(1) the certification of the closed vent system assessment, where applicable, and as required by this Part; and

(2) the information required in Paragraph (6) of Subsection B of 20.2.50.115 NMAC.

G. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.115 NM–C - N, XX/XX/2021]

20.2.50.116 EQUIPMENT LEAKS AND FUGITIVE EMISSIONS:

A. Applicability: Well sites, tank batteries, gathering and boosting stations, natural gas processing plants, transmission compressor stations, and associated piping and components are subject to the requirements of 20.2.50.116 NMAC. Components in water or air service are not subject to the requirements of 20.2.50.116 NMAC. The requirements of this Part may be considered in the facility-wide PTE and in determining the monitoring frequency requirements of this Section.

B. Emission standards: The owner or operator of oil and gas production and processing equipment located at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, or transmission compressor stations shall demonstrate compliance with this Part by performing the monitoring, recordkeeping, and reporting requirements specified in 20.2.50.116 NMAC. Tank batteries supporting multiple facilities are subject to the requirements for the most stringently regulated facility of which they are a part.

C. Default Monitoring requirements: Owners and operators shall comply with the following monitoring requirements:

(1) The owner or operator of a facility with an annual average daily production or average daily throughput of greater than 10 barrels of oil per day or an average daily production of greater than 60,000 standard cubic feet per day of natural gas shall, at least weekly, conduct an external audio, visual, and olfactory (AVO) inspections of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify defects and leaking components as follows:

(a) conduct an external visual inspection for defects, which may include cracks, holes, or gaps in piping or covers; loose connections; liquid leaks; broken or missing caps; broken, cracked or

[95] If there is a facility-wide upset, it would cause all VRUs (and likely other control devices) to go down. In most cases, exhaust gases would be sent to a flare, if one is present, in such situations.
Meyer rebuttal testimony, NMOGA Exhibit 42:2:25-27.

[96] NMOGA does not believe redundant control requirements for VRUs are appropriate. See NMOGA brief.

[97] This language appears in Subsection G.

otherwise damaged seals or gaskets; broken or missing hatches; or broken or open access covers or other closure or bypass devices;

(b) conduct an audio inspection for pressure leaks and liquid leaks;

(c) conduct an olfactory inspection for unusual or strong odors; and

(d) any positive detection during the AVO inspection shall be repaired in accordance with Subsection E if not repaired at the time of discovery.

(2) The owner or operator of a facility with an annual average daily production or average daily throughput of equal to or less than 10 barrels of oil per day or an average daily production of equal to or less than 60,000 standard cubic feet per day of natural gas shall, at least monthly, conduct an external audio, visual, and olfactory (AVO) inspection of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify defects and leaking components as specified in Subparagraphs (a) through (d) of Paragraph (1) of Subsection (C) of 20.2.50.116 NMAC.[98]

(3) The owner or operator of the following facilities shall conduct an inspection using U.S. EPA method 21 or optical gas imaging (OGI) of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify leaking components at a frequency determined according to the following schedules, and upon request by the department for good cause shown:

(a) for existing well sites, inactive well sites, standalone[99] tank batteries, gathering and boosting stations, natural gas processing plants, and transmission compressor stations,[100] the owner or operator shall comply with these requirements within two years of the effective date of this Part.

(b) for well sites and standalone tank batteries:[101]

(ii) annually at facilities with a PTE less than ten tpy VOC;

(iii) semi-annually at facilities with a PTE equal to or greater than ten tpy and less than twenty-five tpy VOC; and

(iv) quarterly at facilities with a PTE equal to or greater than twenty-five tpy VOC.

(c) for gathering and boosting stations and natural gas processing plants:

(i) semiannually at facilities with a PTE less than 25 tpy VOC; and

(ii) quarterly at facilities with a PTE equal to or greater than 25 tpy VOC.

(d) for transmission compressor stations, quarterly or in compliance with the federal equipment leak and fugitive emissions monitoring requirements of New Source Performance Standards, 40 C.F.R. Part 60, as may be revised, so long as the federal equipment leak and fugitive emissions monitoring requirements are at least as stringent as the New Source Performance Standards OOOOa, 40 CFR Part 60, in existence as of the effective date of this Part.

(e) quarterly for well sites within 1,000 feet of an occupied area:

(f) for existing wellhead only facilities, annual inspections shall be completed on the following schedule: 30% by January 1, 2024; 65% by January 1, 2025; and 100% by January 1, 2026.

(g) for well sites that become inactive after the effective date of this Part, annually beginning 30 days after the site becomes an inactive well site.

(4) Inspections using U.S. EPA method 21 shall meet the following requirements:

(a) the instrument shall be calibrated before each day of use by the procedures specified in U.S. EPA method 21 and the instrument manufacturer; and

(b) a leak is detected if the instrument records a measurement of 500 ppm or greater of hydrocarbons, and the measurement is not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

(5) Inspections using OGI shall meet the following requirements:

---

[98] If the EIB determines that proximity LDAR is within its statutory authority, then NMOGA's weekly AVO language could be inserted here: "except that an owner or operator of a well site within 1,000 feet (as measured from the center of the well site to the applicable structure or area of public assembly) of an occupied area shall conduct the AVO inspection at least weekly."

[99] Inserted to prevent conflicts in effective dates between facility types for tank batteries associated with another facility type.

[100] There needs to be an implementation date for these other facilities.

[101] See testimony of John Smitherman, NMOGA Exhibit A1, p. 23:16-24:40; NMOGA Exhibit 58; and Tr. 8:2668 and following.

(a) the instrument shall comply with the specifications, daily instrument checks, and leak survey requirements set forth in Subparagraphs (1) through (3) of Paragraph (i) of 40 CFR 60.18; and

(b) a leak is detected if the emission images recorded by the OGI instrument are not associated with normal equipment operation, such as pneumatic device actuation or crank case ventilation.

(6) Components that are difficult, unsafe, or inaccessible to monitor, as determined by the following conditions, are not required to be inspected until it becomes feasible to do so:

(a) difficult to monitor components are those that require elevating the monitoring personnel more than two meters above a supported surface;

(b) unsafe to monitor components are those that cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring; and

(c) inaccessible to monitor components are those that are buried, insulated, or obstructed by equipment or piping that prevents access to the components by monitoring personnel.

(7) Owners and operators of well sites subject to the requirements in Subparagraph (e) of Paragraph (3) of Subsection C of Section 20.2.50.116 NMAC must conduct an evaluation to determine applicability prior to the applicable compliance date specified in Subparagraph (a) of Paragraph (3) of Subsection C of Section 20.2.50.116 NMAC. An evaluation is not required if the frequency requirements in subparagraph (e) are being met.[102]

(8) An owner or operator conducting an evaluation pursuant to Paragraph (7) of Subsection C of Section 20.2.50.116 NMAC shall measure the distance from the latitude and longitude of the center of each [103]well site to the following points for each type of occupied area:

(a) the property line for indoor or outdoor spaces associated with a school that students use commonly as part of their curriculum or extracurricular activities and outdoor venues or recreation areas;

(b) the property line for outdoor venues or recreation areas, such as a playground, permanent sports field, amphitheater, or other similar place of outdoor public assembly;

(c) the location of a building or structure being[104] used as a place of residency by a person, a family, or families; and

(d) the location of a commercial facility with five-thousand (5,000) or more spare feet of building floor area that is operating and normally occupied during working hours.

(9) Injection well sites and temporarily abandoned well sites are not subject to the leak survey requirements of Paragraphs (3) through (6) of Subsection C of 20.2.50.116 NMAC.

(10) Prior to any monitoring event, the owner or operator shall date and time stamp the monitoring event.

D. **Alternative equipment leak monitoring plans:** As an equivalent means of compliance with Subsection C of 20.2.50.116 NMAC, an owner or operator may comply with the equipment leak requirements through an alternative monitoring plan as follows:

(1) An owner or operator may comply with an individual alternative monitoring plan, subject to the following requirements:

(a) the proposed alternative monitoring plan shall be submitted to and approved by the department prior to conducting monitoring under that plan.

(b) the department may terminate an approved alternative monitoring plan if the department finds that the owner or operator failed to comply with a provision of the plan and failed to correct and disclose the violation to the department within 15 calendar days of identifying the violation.

(c) upon department denial or termination of an approved alternative monitoring plan, the owner or operator shall comply with the default monitoring requirements of Subsection C of 20.2.50.116 NMAC within 15 days.

(2) An owner or operator may comply with a pre-approved monitoring plan maintained by the department, subject to the following requirements:

(a) the owner or operator shall notify the department of the intent to conduct

---

[102] An evaluation of occupied areas should not be required if the frequency under the proposed rule is being used in any event.

[103] Change made to make it clear how the circumference is determined; as stated, it could require multiple measurements around an irregular shape, greatly increasing cost and uncertainty while not creating more protection.

[104] "Used" can mean use in the past. The proposed change makes it clear that the structure is "being" used as an occupied structure.

monitoring under a pre-approved monitoring plan, and identify which pre-approved plan will be used, at least 15 days prior to conducting the first monitoring under that plan.

(b) the department may terminate the use of a pre-approved monitoring plan by the owner or operator if the department finds that the owner or operator failed to comply with a provision of the plan and failed to correct and disclose the violation to the department within 15 calendar days of identifying the violation.

(c) upon department denial or termination of an approved alternative monitoring plan, the owner or operator shall comply with the default monitoring requirements of Subsection C of 20.2.50.116 NMAC within 15 days.

E. Repair requirements: For a leak detected pursuant to monitoring conducted under 20.2.50.116 NMAC:

(1) the owner or operator shall place a visible tag on the leaking component not otherwise repaired at the time of discovery until the component has been repaired;

(2) leaks shall be repaired as soon as practicable but no later than 30 days of discovery;

(3) the equipment must be re-monitored no later than 15 days after the repair of the leak to demonstrate that it has been repaired; and

(4) if the leak cannot be repaired within 30 days of discovery without a process unit shutdown, the leak may be designated "Repair delayed," the date of the scheduled unit shutdown must be indicated, and the leak must be repaired before the end of the scheduled process unit shutdown or within 2 years, whichever is earliest.[105]

(5) if the leak cannot be repaired within 30 days of discovery due to shortage of parts, the leak may be designated "Repair delayed," and must be repaired within 15 days of resolution of such shortage.

F. Recordkeeping requirements:

(1) The owner or operator shall keep a record of the following for all AVO, RM 21, OGI, or alternative equipment leak monitoring inspections conducted as required under 20.2.50.116 NMAC, and shall provide the record to the department upon request:

(a) facility location (latitude and longitude);

(b) time and date stamp, including GPS of the location, of any monitoring;

(c) monitoring method (e.g. AVO, RM 21, OGI, approved alternative method);

(d) name of the person(s) performing the inspection;

(e) a description of any leak requiring repair or a note that no leak was found; and

(f) whether a visible tag was placed on the leak or not;

(2) The owner or operator shall keep the following record for any leak that is detected:

(a) the date the leak is detected;

(b) the date of attempt to repair;

(c) for a leak with a designation of "repair delayed" the following shall be recorded:

(i) reason for delay if a leak is not repaired within the required number of days after discovery. If a delay is due to a parts shortage, a record documenting the attempt to order the parts and the unavailability due to a shortage is required;

(ii) the date of next scheduled process unit shutdown by which the repair will be completed; and

(iii) name[106] of the person(s) who determined that the repair could not be implemented without a process unit shutdown.

(d) date of successful leak repair;

(e) date the leak was monitored after repair and the results of the monitoring; and

(f) a description of the component that is designated as difficult, unsafe, or inaccessible to monitor, an explanation stating why the component was so designated, and the schedule for repairing and monitoring the component.

(3) For a leak detected using OGI, the owner or operator shall keep records of the specifications, the daily instrument check, and the leak survey requirements specified at 40 CFR 60.18(i)(1)-(3).

(4) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

---

[105] This change is to clarify and make the procedure more definite by identifying the scheduled date of the process unit shutdown where the change will occur. Additional records are required. NMED has indicated conceptual agreement with this change.

[106] Signature implies a wet signature, which is difficult to maintain in electronic databases.

G. Reporting requirements:

(1) The owner or operator shall certify the use of an alternative equipment leak monitoring plan under Subsection D of 20.2.50.116 NMAC to the department annually, if used.

(2) The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.116 NMAC - N, XX/XX/2021]

20.2.50.117 NATURAL GAS WELL LIQUID UNLOADING: [107]

A. Applicability: Liquid unloading operations resulting in the venting of natural gas at natural gas wells are subject to the requirements of 20.2.50.117 NMAC. Liquid unloading operations that do not result in the venting of any natural gas are not subject to this Part. Owners and operators of a natural gas well subject to this Part must comply with the standards set forth in Paragraph (1[108]) of Subsection B of 20.2.50.117 NMAC within two years of the effective date of this Part.[109]

B. Emission standards:[110]

(1) The owner or operator of a natural gas well shall use at least one of the following best management practices during the life of the well to avoid the need for venting of natural gas associated with liquid unloading:

(a) use of a plunger lift;

(b) use of artificial lift;

(c) use of a control device;

(d) use of an automated control system; or

(e) other control if approved by the department

(2) The owner or operator of a natural gas well shall use the following best management practices during venting associated with liquid unloading to minimize emissions, consistent with well site conditions and good engineering practices:

(a) reduce wellhead pressure before blowdown or venting to atmosphere;

(b) monitor manual venting associated with liquid unloading in close proximity to the well or via remote telemetry; and

(c) close vents to the atmosphere and return the well to normal production operation as soon as practicable.[111]

C. Monitoring requirements:

(1) The owner or operator shall monitor the following parameters during venting associated with liquid unloading:

(a) wellhead pressure;

(b) flow rate of the vented natural gas (to the extent feasible); and

(c) duration of venting to the storage vessel, tank battery, or atmosphere.

(2) The owner or operator shall calculate the volume and mass of VOC emitted during a venting event associated with a liquid unloading event.

(3) The owner or operator shall comply with the monitoring requirements of 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator shall keep the following records for liquid unloading:

(a) unique identification number and location (latitude and longitude) of the well;

(b) date of the unloading event;

---

[107] Kuehn/Palmer testimony, NMED Exhibit 32:95:1-26, 96:1-6. The proposed operational requirements and best management practices for limiting VOC emissions during natural gas well liquids unloading events are based on requirements in Colorado Reg. 7, Pennsylvania GP-5 and GP-5A, and the Wyoming Permitting Guidance.

[108] The provisions of former paragraph (3) moved to paragraph (1). This reflects that move.

[109] NMOGA Exhibit A1, Smitherman testimony, NMOGA Exhibit A1:25:1-46. Mr. Smitherman testified that the rule should be modified to recognize that only manual liquid unloading events that result in venting of gas to the atmosphere are covered, since there is no benefit to emissions reductions to apply to activities that do not cause emissions.

[110] Davis testimony, IPANM Exhibit 2:7-12. Mr. Davis testified in support of the best management practices to reduce emissions associated with manual liquids unloading, but his testimony also opposed the equipment monitoring tracking throughout the proposed regulation.

[111] Smitherman testimony, NMOGA Exhibit A1:25:29-36. Mr. Smitherman testified that closing the vent valve as soon as practical after an unloading event will help minimize venting volumes.

(c) wellhead pressure;

(d) flow rate of the vented natural gas (to the extent feasible. If not feasible, the owner or operator shall use the maximum potential flow rate in the emission calculation);

(e) duration of venting to the storage vessel, tank battery, or atmosphere;

(f) a description of the management practice used to minimize venting of VOC emissions before and during the liquid unloading;

(g) the type of control device or control technique used to control VOC emissions during venting associated with the liquid unloading event; and

(h) a calculation of the VOC emissions vented during a liquid unloading event based on the duration, calculated volume, and composition of the produced gas.

(2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.117 NMAC - N, XX/XX/2021]

20.2.50.118 GLYCOL DEHYDRATORS:

A. Applicability: Glycol dehydrators with a PTE equal to or greater than two tpy of VOC and located at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.118 NMAC.

B. Emission standards:

(1) Existing glycol dehydrators with a PTE equal to or greater than two tpy of VOC shall achieve a minimum combined capture and control efficiency of ninety-five percent of VOC emissions from the still vent and flash tank (if present) no later than two years after the effective date of this Part. If a combustion control device is used, the combustion control device shall have a minimum design combustion efficiency of ninety-eight percent.[113]

(2) New glycol dehydrators with a PTE equal to or greater than two tpy of VOC shall achieve a minimum combined capture and control efficiency of ninety-five percent of VOC emissions from the still vent and flash tank (if present) upon startup. If a combustion control device is used, the combustion control device shall have a minimum design combustion efficiency of ninety-eight percent.

(3) The owner or operator of a glycol dehydrator shall comply with the following requirements:

(a) still vent and flash tank emissions shall be routed at all times to the reboiler firebox, condenser, combustion control device, fuel cell, to a process point that either recycles or recompresses the emissions or uses the emissions as fuel, or to a VRU that reinjects the VOC emissions back into the process stream or natural gas pipeline;

(b) if a VRU is used, it shall consist of a closed loop system of seals, ducts, and a compressor that reinjects the vapor into the process or the natural gas pipeline. The VRU shall be operational at least ninety-five percent of the time the controlled equipment is in operation, resulting in a minimum combined capture and control efficiency of ninety-five percent, which shall supersede any inconsistent requirements in 20.2.50.115 NMAC.[114] The VRU shall be installed, operated, and maintained according to the manufacturer's specifications; and[115]

(c) still vent and flash tank emissions shall not be vented directly to the atmosphere during normal operation.[116]

---

[113] Textor rebuttal testimony, NMOGA Exhibit 46: Textor rebuttal testimony, NMOGA Exhibit 46: 13:39-44, 14:1-14. Ms. Textor testified that not all glycol dehydrators have a flash tank, which could make the compliance requirement unclear. Including "where present" addresses this concern.

[114] Ms. Bisbey-Kuehn testified that she was agreeable to this change to address the inconsistency between the allowed 95% downtime and the redundant VRU requirement in 20.2.50.115 NMAC. Bisbey-Kuehn Testimony, Tr. 7:2322:2-6

[115] Textor rebuttal testimony, NMOGA Exhibit 46: 14:16-26. Ms. Textor testified that the term "vapor" should replace "natural gas" because the off gases from a flash tank have a lower methane content than natural gas would have. Ms. Textor also testified that the redundant VRU concept must be clarified for purposes of glycol dehydrators. Rebuttal Testimony of Marise Textor, NMOGA Exhibit 46:15:39-46 – 16:1-16. This language clarifies that the redundant VRU requirement does not supersede the allowed 5% downtime.

[116] Textor rebuttal testimony, NMOGA Exhibit 46: 14:28-45, 15:1-16. Ms. Textor testified that prohibiting still vent and flash

(4) an owner or operator complying with the requirements in Subsection B of 20.2.50.118 NMAC through use of a control device shall comply with the requirements in 20.2.50.115 NMAC.

(5) The requirements of Subsection B of 20.2.50.118 NMAC cease to apply when the actual annual VOC emissions from a new or existing glycol dehydrator are less than two tpy VOC.

C. Monitoring requirements:

(1) The owner or operator of a glycol dehydrator shall conduct an annual extended gas analysis on the dehydrator inlet gas and calculate the uncontrolled and controlled VOC emissions in tpy.

(2) The owner or operator of a glycol dehydrator shall inspect the glycol dehydrator, including the reboiler and regenerator, and the control device or process the emissions are being routed, semi-annually to ensure it is operating as initially designed and in accordance with the manufacturer recommended operation and maintenance schedule.

(3) Prior to any monitoring event, the owner or operator shall date and time stamp the event, and the monitoring data entry shall be made in accordance with the requirements of this Part.

(4) An owner or operator complying with the requirements in Subsection B of 20.2.50.118 NMAC through the use of a control device shall comply with the monitoring requirements in 20.2.50.115 NMAC.

(5) Owners and operators shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator of a glycol dehydrator shall maintain a record of the following:

(a) unique identification number and dehydrator location (latitude and longitude);

(b) glycol circulation rate, monthly natural gas throughput, and the date of the most recent throughput measurement;

(c) data and methodology used to estimate the PTE of VOC (must be a department approved calculation methodology);

(d) controlled and uncontrolled VOC emissions in tpy;

(e) type, make, model, and unique identification number of the control device or process the emissions are being routed;

(f) time and date stamp, including GPS of the location, of any monitoring;

(g) results of any equipment inspection, including maintenance or repair activities required to bring the glycol dehydrator into compliance; and

(h) a copy of the glycol dehydrator manufacturer specifications.

(2) An owner or operator complying with the requirements in Paragraph (1) or (2) of Subsection B of 20.2.50.118 NMAC through use of a control device as defined in this Part shall comply with the recordkeeping requirements in 20.2.50.115 NMAC.

(3) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.118 NMAC - N, XX/XX/2021]

20.2.50.119 HEATERS:

A. Applicability: Natural gas-fired heaters with a rated heat input equal to or greater than 20 MMBtu/hour including heater treaters, heated flash separators, evaporator units, fractionation column heaters, and glycol dehydrator reboilers in use at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.119 NMAC.[117]

B. Emission standards:

(1) Natural gas-fired heaters shall comply with the emission limits in table 1 of 20.2.50.119 NMAC.

Table 1 - EMISSION STANDARDS FOR NO_x AND CO

Date of Construction:	NO_x	CO

tank emissions venting to the atmosphere at all times is not possible, as there are unavoidable releases such as those due to emissions vented to the atmosphere via air pollution control equipment downstream of control. Prohibiting direct venting during normal operations better captures the regulation's goal.

[117] Lisowski rebuttal testimony, NMOGA Exhibit 43:12:22-35.

	(ppmvd @ 3% O_2)	(ppmvd @ 3% O_2)
Constructed or reconstructed before the effective date of 20.2.50 NMAC	30	400[118]
Constructed or reconstructed on or after the effective date of 20.2.50 NMAC	30	400

(2) Existing natural gas-fired heaters shall comply with the requirements of 20.2.50.119 NMAC no later than three years after the effective date of this Part.[119]

(3) New natural gas-fired heaters shall comply with the requirements of 20.2.50.119 NMAC upon startup.

C. Monitoring requirements:

(1) The owner or operator shall:

(a) conduct emission testing for NOx and CO within 180 days of the compliance date specified in Paragraph (2) or (3) of Subsection B of 20.2.50.119 NMAC and at least every two years thereafter.

(b) inspect, maintain, and repair the heater in accordance with the manufacturer specifications at least once every two years following the applicable compliance date specified in 20.2.50.119 NMAC. The inspection, maintenance, and repair shall include the following:

(i) inspecting the burner and cleaning or replacing components of the burner as necessary;

(ii) inspecting the flame pattern and adjusting the burner as necessary to optimize the flame pattern consistent with the manufacturer specifications;

(iii) inspecting the AFR controller and ensuring it is calibrated and functioning properly, if present;

(iv) optimizing total emissions of CO consistent with the NO_x requirement and manufacturer specifications, and good combustion practices; and

(v) measuring the concentrations in the effluent stream of CO in ppmvd and O_2 in volume percent before and after adjustments are made in accordance with Subparagraph (c) of Paragraph (2) of Subsection C of 20.2.50.119 NMAC.

(2) The owner or operator shall comply with the following periodic testing requirements:

(a) conduct three test runs of at least 20-minutes duration within ten percent of one-hundred percent peak, or the highest achievable, load;

(b) determine NO_X and CO emissions and O_2 concentrations in the exhaust with a portable analyzer used and maintained in accordance with the manufacturer specifications and following the procedures specified in the current version of ASTM D6522;

(c) if the measured NO_X or CO emissions concentrations are exceeding the emissions limits of table 1 of 20.2.50.119 NMAC, the owner or operator shall repeat the inspection and tune-up in Subparagraph (b) of Paragraph (1) of Subsection C of 20.2.50.119 NMAC within 30 days of the periodic testing; and

(d) if at any time the heater is operated in excess of the highest achievable load in a prior test plus ten percent, the owner or operator shall perform the testing specified in Subparagraph (a) of Paragraph (2) of Subsection C of 20.2.50.119 NMAC within 60 days from the anomalous operation.

(3) When conducting periodic testing of a heater, the owner or operator shall follow the procedures in Paragraph (2) of Subsection C of 20.2.50.119 NMAC. An owner or operator may deviate from those procedures by submitting a written request to use an alternative procedure to the department at least 60 days before performing the periodic testing. In the alternative procedure request, the owner or operator must demonstrate the alternative procedure's equivalence to the standard procedure. The owner or operator must receive written approval from the department prior to conducting the periodic testing using an alternative procedure.

(4) Prior to a monitoring event, the owner or operator shall date and time stamp the event, and the required monitoring data entry shall be made in accordance with this Part.

(5) The owner or operator shall comply with the monitoring requirements of 20.2.50.112 NMAC.

D. Recordkeeping requirements: The owner or operator shall maintain a record of the following:

---

[118] Tr. 6:1944:7-13. NMED agreed with NMOGA's proposal to modify the CO emission limit for new and existing heaters from 300 ppmv to 400 for all units.

[119] Tr. 6:1944:14-17. NMED agreed with NMOGA's proposed extension of the compliance timeline to three years.

(1) unique identification number and location (latitude and longitude) of the heater;

(2) summary of the complete test report and the results of periodic testing; and

(3) inspections, testing, maintenance, and repairs, which shall include at a minimum:

(a) the date and time stamp, including GPS of the location, of the inspection, testing, maintenance, or repair conducted;

(b) name of the person(s) conducting the inspection, testing, maintenance, or repair;

(c) concentrations in the effluent stream of CO in ppmv and O_2 in volume percent; and

(d) the results of the inspections and any the corrective action taken.

(4) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.119 NMAC - N, XX/XX/2021]

20.2.50.120 HYDROCARBON LIQUID TRANSFERS:

A. Applicability: Hydrocarbon liquid transfers located at existing well sites, standalone tank batteries, gathering and boosting stations with one or more controlled storage vessels, natural gas processing plants, or transmission compressor stations are subject to the requirements of 20.2.50.120 NMAC within two years of the effective date of this Part. Hydrocarbon liquid transfers at existing gathering and boosting stations (including associated tank batteries) without any controlled storage vessels are subject to the requirements of 20.2.50.120 NMAC on the schedule specified in Paragraph 1 of Subsection B of 20.2.50.123 NMAC.[120] Hydrocarbon liquid transfers located at new well sites, tank batteries, gathering and boosting stations, natural gas processing plants, or transmission compressor stations are subject to the requirements of 20.2.50.120 NMAC upon startup. (1)[121] Any facility connected to oil sales pipelines that are routinely used for hydrocarbon liquid transfers are not subject to the requirements of 20.2.50.120 NMAC. (2) Well sites, tank batteries, gathering and boosting stations, natural gas processing plants, or transmission compressor stations not connected to an oil sales pipeline that load out hydrocarbon liquids to trucks fewer than thirteen (13) times in a calendar year are not subject to 20.2.50.120 NMAC. (3) When transferring hydrocarbon liquid from a transfer vessel to a storage vessel subject to the emission standards in 20.2.50.123 NMAC, no requirements under this Section apply.[122]

B. Emission standards:

(1) The owner or operator of a hydrocarbon liquid transfer operation shall use vapor balance, vapor recovery, or a control device to control VOC emissions by at least ninety-five percent, when transferring hydrocarbon liquid from a storage vessel to a tanker truck or tanker railcar for transport. If a combustion control device is used, the combustion device shall have a minimum design combustion efficiency of ninety-eight percent.

(2) An owner, operator, or personnel conducting the hydrocarbon liquid transfer using vapor balance shall:

(a) transfer the vapor displaced from the transfer truck or railcar being loaded back to the storage vessel being emptied via a pipe or hose connected before the start of the transfer operation. If multiple storage vessels are manifolded together in a tank battery, the vapor may be routed back to any storage vessel in the tank battery;

(b) ensure that the transfer does not begin until the vapor collection and return system is properly connected;

(c) inspect connector pipes, hoses, couplers, valves, and pressure relief devices for leaks;

(d) check the hydrocarbon liquid and vapor line connections for proper connections before commencing the transfer operation; and

(e) operate transfer equipment at a pressure that is less than the pressure relief valve setting of the receiving transport vehicle or storage vessel.

[120] See NMOGA Brief at II.I.

[121] NMOGA believes that breaking these provisions into separate paragraphs enhances clarity.

[122] Smitherman testimony, NMOGA Exhibit A1:26:38-46, 27:1-2. Mr. Smitherman testified that it is economically impractical to capture vapors associated with hydrocarbon liquid transfer where a well production facility is connected to and utilizes an oil pipeline for routine oil sales. Associated VOC emissions would be small, since oil pipelines are typically reliable and truck loading is rare.

(3) Connector pipes and couplers shall be inspected and maintained free of liquid leaks.

(4) Connections of hoses and pipes used during hydrocarbon liquid transfers shall be supported on drip trays that collect any leaks, and the materials collected shall be returned to the process or disposed of in a manner compliant with state law.

(5) Liquid leaks that occur shall be cleaned and disposed of in a manner that minimizes emissions to the atmosphere, and the material collected shall be returned to the process or disposed of in a manner compliant with state law.

(6) An owner or operator complying with Paragraph (1) of Subsection B of 20.2.50.120 NMAC through use of a control device shall comply with the control device requirements in 20.2.50.115 NMAC.

C. Monitoring requirements:

(1) The owner, operator, or their designated representative shall visually inspect the hydrocarbon liquid transfer equipment monthly at staffed locations and semi-annually at unstaffed locations to ensure that hydrocarbon liquid transfer lines, hoses, couplings, valves, and pipes are not dripping or leaking. At least once per calendar year, the inspection shall occur during a transfer operation. Leaking components shall be repaired to prevent dripping or leaking before the next transfer operation, or measures must be implemented to mitigate leaks until the necessary repairs are completed.[123]

(2) The owner or operator of a hydrocarbon liquid transfer operation controlled by a control device must follow manufacturer specifications for the device. **(3)** Owners and operators complying with Paragraph (1) of Subsection B of 20.2.50.120 NMAC through use of a control device shall comply with the monitoring requirements in 20.2.50.115 NMAC.

(4) Prior to any monitoring event, the owner or operator shall date and time stamp the event, and the monitoring data entry shall be made in accordance with the requirements of this Part.

(5) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator shall maintain a record of the following:

(a) the location of the facility;

(b) if using a control device, the type, make, and model of the control device;

(c) the date and time stamp, including GPS of the location, of any inspection;

(d) the name of the person(s) conducting the inspection;

(e) a description of any problem observed during the inspection; and

(f) the results of the inspection and a description of any repair or corrective action taken.

(2) The owner or operator shall maintain a record for each site of the annual total hydrocarbon liquid transferred and annual total VOC emissions. Each calendar year, the owner or operator shall create a company-wide record summarizing the annual total hydrocarbon liquid transferred and the annual total calculated VOC emissions.

(3) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.120 NMAC - N, XX/XX/2021]

20.2.50.121 PIG LAUNCHING AND RECEIVING:[124]

A. Applicability: Individual pipeline pig launcher and receiver operations with a PTE equal to or greater than one tpy VOC located within the property boundary of, and under common ownership or control with, well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.121 NMAC.[125]

[123] Smitherman testimony, NMOGA Exhibit A1:27:37-46. Mr. Smitherman testified that it is no feasible for the owner/operator to inspect every hydrocarbon liquid transfer, because most well production facilities are unmanned.

[124] NMOGA has argued this section should be stricken in its entirety. *See* NMOGA Final Brief.

[125] Textor rebuttal testimony, NMOGA Exhibit 46:3-5. Ms. Textor testified that the rule should only apply to those individual onsite pig launchers or receivers with emissions greater than or equal to one ton per year VOC to improve cost effectiveness.;

B. Emission standards:

(1) Owners and operators of affected pipeline pig launcher and receiver operations shall capture and reduce VOC emissions from pigging operations by at least ninety-five percent within two years of the effective date of this Part. If a combustion control device is used, the combustion device shall have a minimum design combustion efficiency of ninety-eight percent.[126]

(2) The owner or operator conducting an affected pig launching and receiving operation shall:[127]

(a) employ best management practices to minimize the liquid present in the pig receiver chamber and to minimize emissions from the pig receiver chamber to the atmosphere after receiving the pig in the receiving chamber and before opening the receiving chamber to the atmosphere;

(b) employ a method to minimize emissions, such as installing a liquid ramp or drain, routing a high-pressure chamber to a low-pressure line or vessel, using a ball valve type chamber, or using multiple pig chambers;

(c) recover and dispose of receiver liquid in a manner that minimizes emissions to the atmosphere to the extent practicable; and

(d) ensure that the material collected is returned to the process or disposed of in a manner compliant with state law.

(3) The emission standards in Paragraphs (1) and (2) of Subsection B of 20.2.50.121 NMAC cease to apply to an individual pipeline pig launching and receiving operation if the actual annual VOC emissions of the launcher or receiver operation are less than one tpy of VOC.

(4) An owner or operator complying with Paragraph (2) of Subsection B of 20.2.50.121 NMAC through use of a control device shall comply with the control device requirements in 20.2.50.115 NMAC. An owner or operator complying through use of a portable control device shall install the device consistent with manufacturer's specifications and is not subject to the requirements of 20.2.50.115 NMAC.

C. Monitoring requirements:

(1) The owner or operator of an affected pig launching and receiving site shall inspect the equipment for leaks using AVO, RM 21, or OGI on either:

(a) a monthly basis if pigging operations at a site occur on a monthly basis or more frequently; or

(b) prior to the commencement and after the conclusion of the pig launching or receiving operation, if less frequent.[128]

(2) The monitoring shall be performed using the methodologies outlined in Subsection (C) of 20.2.50.116 NMAC as applicable and at the frequency required in Paragraph (1) of Subsection (C) of 20.2.50.121 NMAC. The monitoring shall be performed when the pig trap is under pressure.

(3) An owner or operator complying with Paragraph (1) of Subsection B of 20.2.50.121 NMAC through use of a control device shall comply with the monitoring requirements in 20.2.50.115 NMAC. A portable control device shall be installed consistent with manufacturer's specifications and is not subject to the requirements of 20.2.50.115 NMAC.

(4) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator of an affected pig launching and receiving site shall maintain a record of the following:

(a) the pigging operation, including the location, date, and time of the pigging operation;

Textor rebuttal testimony, NMOGA Exhibit 46:6:34-44, 7:1-14. Ms. Textor testified that it is not feasible to install a pipeline pressure storage tank, a vapor recovery system on a depressurization vessel, and a compressor at off-site locations. Similarly, facilities to control emissions such as flares or combustors would virtually never be available at offsite locations and would need to be brought in as portable equipment for each pigging event, further escalating costs.

[126] Textor rebuttal testimony, NMOGA Exhibit 46: 8:29-45, 9:1-32. Ms. Textor testified that a emissions reduction of 98% would be difficult to achieve, because devices only achieve that level under steady state conditions. Efficiency in practice will be lower, so the rule should require no more than a design destruction efficiency of 95% control efficiency.

[127] Textor rebuttal testimony, NMOGA Exhibit 46: 10:7-27. Ms. Textor testified that emissions cannot be prevented, they can only be minimized. The rule's language should reflect that.

[128] Textor rebuttal testimony, NMOGA Exhibit 46: 11:31-41. Ms. Textor testified that monthly inspections and inspections before and immediately after launch are more cost effective and likely as effective in reducing emissions.

(b) the data and methodology used to estimate the actual emissions to the atmosphere and used to estimate the PTE;

(c) date and time of any monitoring and the results of the monitoring; and

(d) the type of control device and its make and model.

(2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.121 NMAC - N, XX/XX/2021]

20.2.50.122 PNEUMATIC CONTROLLERS AND PUMPS:

A. Applicability: Natural gas-driven pneumatic controllers and pumps located at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.122 NMAC.

B. Emission standards:

(1) A newnatural gas-driven pneumatic controller or pump shall comply with the requirements of 20.2.50.122 NMAC upon startup.

(2) An existing natural gas-driven pneumatic pump shall comply with the requirements of 20.2.50.122 NMAC within three years of the effective date of this Part.

(3) An owner or operator shall ensure that its existing natural gas-driven pneumatic controllers shall comply with the requirements of 20.2.50.122 NMAC according to the following schedule[129]:

Table 1 – WELL SITES, STAND ALONE TANK BATTERIES, GATHERING AND BOOSTING STATIONS

Total Historic Percentage of Non-Emitting Controllers	Total Required Percentage of Non-Emitting Controllers by January 1, 2024	Total Required Percentage of Non-Emitting Controllers by January 1, 2027	Total Required Percentage of Non-Emitting Controllers by January 1, 2030
> 75%	80%	85%	90%
> 60-75%	80%	85%	90%
> 40-60%	65%	70%	80%
> 20-40%	45%	70%	80%
0-20%	25%	65%	80%

Table 2 – TRANSMISSION COMPRESSOR STATIONS AND GAS PROCESSING PLANTS

Total Historic Percentage of Non-Emitting Controllers	Total Required Percentage of Non-Emitting Controllers by January 1, 2024	Total Required Percentage of Non-Emitting Controllers by January 1, 2027	Total Required Percentage of Non-Emitting Controllers by January 1, 2030
> 75%	80%	95%	98%
> 60-75%	80%	95%	98%
> 40-60%	65%	95%	98%
> 20-40%	50%	95%	98%
0-20%	35%	95%	98%

(4) Standards for natural gas-driven pneumatic controllers.

(a) new pneumatic controllers shall have an emission rate of zero. A natural gas driven pneumatic controller replacing an existing natural gas driven pneumatic controller at an existing facility is an

[129] Change made to reflect testimony by Ms. Kuehn and evident intent of provision to require each owner/operator to reduce the number of pneumatic controllers in its operations by the specified percentage. It is obvious from the testimony of all witnesses that an individual controller cannot partially reduce emissions but must be retrofitted to a non-emitting controller or replaced or eliminated. It is obvious from the testimony of all witnesses that the reduction percentages are aimed at the group of existing controllers as an individual controller cannot partially reduce emissions but must be retrofitted to a non-emitting controller or replaced or eliminated. Bisbey-Kuehn testimony, Tr. 7:2027:9-13 ("the proposed provisions of this section will likely achieve higher emission reductions from pneumatic controllers by targeting reductions in the overall number of emitting controllers…"); 7:2029:6-7:2030:9 (referencing changes to the "fleet" of controllers).

existing pneumatic controller for purposes of Section 20.2.50.122.[130]

(b) owners and operators of existing pneumatic controllers shall meet the required percentage of non-emitting controllers within the deadlines in tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC, and shall comply with the following:

(i) by July 1, 2023,[131] the owner or operator shall determine the total controller count for all controllers subject to each table separately[132] at all of the owner or operator's affected facilities that commenced construction before the effective date of this Part. The total controller count for each table must include all emitting pneumatic controllers and all non-emitting pneumatic controllers, except that pneumatic controllers necessary for a safety or process purpose that cannot otherwise be met without emitting natural gas shall not be included in the total controller count. This final number is the total historic controller count. Controllers identified as required for a safety or process purpose after July 1, 2023 shall not affect the total historic controller count.[133]

(ii) determine which controllers in the total controller count for each table are non-emitting and sum the total number of non-emitting controllers and designate those as total historic non-emitting controllers.

(iii) determine the total historic non-emitting percent of controllers for each table by dividing the total historic non-emitting controller count by the total historic controller count and multiplying by 100.

(iv) based on the percent calculated in (iii) above for each table, the owner or operator shall determine which provisions of tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC apply and the replacement schedule the owner or operator must meet.

(v) if an owner or operator meets at least seventy-five percent total non-emitting controllers using the calculation methodology in paragraph (4)(c)[134] by January 1, 2025, for either or both table 1 or table 2, the owner or operator is not thereafter[135] subject to the requirements of that table(s) of Paragraph (3) of Subsection B of 20.2.50.122 NMAC.

(vi) if after January 1, 2027, an owner or operator's remaining pneumatic controllers are not cost-effective to retrofit, the owner or operator may submit a cost analysis of retrofitting those

---

[130] In her testimony, Ms. Kuehn clearly stated that "like kind replacement" of existing controllers at existing facilities should not trigger the "new" controller provision, to avoid inadvertent or unplanned conversion of facilities. Kuehn/Palmer testimony, Tr. 7:2039:12-17; NMOGA Exhibit 47, 46:38-40, 48:35 – 49:2.

[131] Ms. Kuehn stated a general intent to achieve a January 1, 2023 date. Kuehn/Palmer testimony, Tr. 7:2042:8-11. However, the progress of the rulemaking has been slower, Ms. Kuehn agreed that more devices may be needed for safety or process purposes, Kuhn/Palmer testimony, Tr. 7:2040:2-2041:5. Mr. Smitherman testified that this couldn't be done in 6 months, Smitherman testimony, Tr. 7:2108:11-27, Ms. Nolting testified that completing the inventory was extremely time consuming already, Nolting testimony, Tr. 7:2284:19-21,:and Ms. Kuehn testified that the documentation was needed only for those that would otherwise be phased out, which suggests a rolling evaluation (for other than high-bleed devices), which reduces the immediate burden. Kuehn/Palmer testimony, Tr. 7:2041:10-20. Given this testimony and the fact that the first deadline for reductions is January 1, 2024, NMOGA believes that Ms. Kuehn may not have appreciated the infeasibility of the January 1, 2023 date in light of the changes discussed and the role of pneumatic controllers needed for safety or process reasons. NMOGA believes a July 1, 2023 date provides more time for the resource intensive inventory. This would also be the date used to "set" the phase out schedule in tables 1 and 2. This then gives owners/operators 66 more months to ensure that they can meet the first phase out deadline on January 1, 2024.

[132132] Ms. Kuehn's testimony is based upon reductions occurring at each "group" of table 1 or table 2 facilities. However, the calculation methodology does not distinguish between the table 1 and table 2 facilities. Separate calculation for each table is needed to create an "apples to apples" comparison to track progress between "historic" and January 1, 2024, January 1, 2027 and January 1, 2030 performance. Otherwise, an operator's failure to make progress at its table 1 sites may result in its table 2 sites being in violation and vice versa. This is surely not the intended result.

[133] Change made to reflect reality that not all devices required for safety or process reasons will be known by either January 1, 2023 or July 1, 2023. Kuehn/Palmer testimony, Tr. 7:2042:5-7 (conceding that "ideally" the devices could be identified by January 1, 2023). As Mr. Smitherman testified, some of these devices are necessary to provide a safe working environment and the rule needs to allow this. Smitherman testimony, NMOGA Exhibit A1:30:4-16. The change allows for future additions but provides that they do not affect the total historic controller count used to establish obligations under tables 1 and 2. NMOGA believes that this is consistent with the Department's intent and provides a route to maintain controllers required for safety or process reasons if missed during the initial pass.

[134] This provision is added to establish how to count non-emitting controllers for compliance purposes after the initial count. See the rationale for Paragraph (4)(c) below for details.

[135] Change made to reflect Ms. Kuehn's testimony that sources that meet the 75% prior to January 1, 2025 date must still meet the January 1, 2024 reduction percentage. Kuehn/Palmer testimony, Tr. 7:2043:16-7:2045:21.

remaining units to the department. The department shall review the cost analysis and determine whether those units qualify for a waiver from meeting additional retrofit requirements.

(c) owners and operators of existing natural gas driven pneumatic controllers shall demonstrate compliance with tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC, on January 1, 2024, January 1, 2027, and January 1, 2030, as follows:

(i) determine which controllers are emitting (excluding pneumatic controllers necessary for safety or process reasons pursuant to Paragraph (4)(d) of Subsection B of 20.2.50.122 NMAC) and sum the total number of emitting controllers for table 1 and table 2 facilities separately.

(ii) determine the percentage of non-emitting controllers by using the following equation for table 1 and table 2 facilities separately:

Total percentage of non-emitting controllers = 100 – ((total emitting controllers / total historic controller count) x 100)

(iii) compliance is demonstrated if the Total Percentage of Non-Emitting Controllers calculated pursuant to Paragraph (4)(c)(ii) is less than or equal to the value for that year in the Total Historic Percentage of Non-Emitting Controllers row (calculated in Paragraph (4)((b)(iv)) of table 1 or table [136]2, as applicable, of Paragraph (3) of Subsection B of 20.2.50.122 NMAC.

(d) No later than January 1, 2024[137], a pneumatic controller with a bleed rate greater than six standard cubic feet per houris permitted only when the owner or operator has demonstrated that a higher bleed rate is required based on functional needs, including response time, safety, and positive actuation. An owner or operator that seeks to maintain operation of an emitting pneumatic controller as excepted for process or safety reasons under clause (i) of subparagraph (a) of Paragraph (4) of Subsection B of 20.2.50.122 NMAC must prepare and document the justification for the safety or process purpose prior to the installation of a new emitting controller or the retrofit of an existing controller.[138] The justification shall be certified by a qualified professional or inhouse engineer.

(e) Temporary pneumatic controllers that emit natural gas and are used for well abandonment activities or used prior to or through the end of flowback, and pneumatic controllers used as emergency shutdown devices located at a well site, are not subject to the requirements of Subsection B of 20.2.50.122 NMAC.

(f) Temporary or portable pneumatic controllers that emit natural gas and are on-site for less than 90 days are not subject to the requirements of Subsection B of 20.2.50.122 NMAC.

(5) Standards for natural gas-driven pneumatic diaphragm pumps.

(a) new pneumatic diaphragm pumps located at natural gas processing plants shall have an emission rate of zero.

(b) new pneumatic diaphragm pumps located at well sites, tank batteries, gathering

---

[136] The rule as drafted does not establish a compliance methodology to demonstrate compliance with the January 1, 2024, 2027 and 2030 compliance dates. NMOGA proposes new paragraph (4)(c) to meet this need. While tables 1 and 2 talk about percent of "non-emitting controllers," for purposes of phasing out, what is important is reducing the number of emitting controllers. In addition, Paragraph (1) of both Subsections C and D do not require records of non-emitting controllers, so there is no non-emitting controller data to use. Therefore, NMOGA uses the "emitting controller count," excluding pneumatic controllers "permitted" because necessary for safety or process reasons. Kuehn/Palmer testimony, Tr. 7:2041:1-5. NMOGA then proposes use of the equation: 100 – ((existing controller count (in 2024, 2027 or 2030) / total historic controller count) x 100, which gives a final value directly comparable to tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC. In essence, if 100% is the total number of emitting and non-emitting controllers, and we subtract the percentage of emitting controllers, what is left is the percentage of non-emitting controllers.

[137] Upon reviewing the final language, NMOGA realized that this provision "phases out" high-bleed devices unless the required demonstration is made. This cannot be accomplished by the effective date. In its proposal, NMOGA had proposed to phase out all non-safety/process high-bleed controllers within two years. NMOGA thus proposes to align the phase out with the January 1, 2024 first compliance date, allowing just less than two-years to inventory and prepare the justification for high bleeds, resulting in an effective phase out. NMOGA Exhibit 47, 48:33-34 ("High Bleed Controller shall be retrofitted or replaced no later than January 1, 2024 unless" demonstrated as necessary for safety or process reasons).

[138] NMOGA appreciates the inclusion of this provision as certain pneumatic controllers are required for process and safety reasons. NMOGA believes, however, that the language as currently written might "freeze" in place high-bleed devices (to qualify for the exception) when low-bleed or intermittent devices might be used. In her testimony, Ms. Kuehn indicated that this was not the Department's intent. The language changes reflect that discussion and allow lower emitting devices to be substituted for higher emitting ones. This advances the goal of reducing release of natural gas.

and boosting stations, or transmission compressor stations with access to commercial line electrical power shall have an emission rate of zero.

(c) existing pneumatic diaphragm pumps located at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, or transmission compressor stations with access to commercial line electrical power shall have an emission rate of zero within two years of the effective date of this Part.

(d) owners and operators of pneumatic diaphragm pumps located at well sites, tank batteries, gathering and boosting stations, or transmission compressor stations without access to commercial line electrical power shall reduce VOC emissions from the pneumatic diaphragm pumps by ninety-five percent if it is technically feasible to route emissions to a control device, fuel cell, or process. If there is a control device available onsite but it is unable to achieve a ninety-five percent emission reduction, and it is not technically feasible to route the pneumatic diaphragm pump emissions to a fuel cell or process, the owner or operator shall route the pneumatic diaphragm pump emissions to the control device within two years of the effective date of this Part.

C. Monitoring requirements:

(1) Pneumatic controllers or diaphragm pumps not using natural gas or other hydrocarbon gas as a motive force are not subject to the monitoring requirements in Subsection C of 20.2.50.122 NMAC.

(2) No later than January 1, 2023,[139] the owner or operator of a facility with one or more natural gas-driven pneumatic controllers subject to the deadlines set forth in tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC shall monitor the compliance status of each subject pneumatic controller at each facility.

(3) The owner or operator of a natural gas-driven pneumatic controller shall, on a monthly basis, conduct an AVO or OGI inspection, and shall also inspect the pneumatic controller, perform necessary maintenance (such as cleaning, tuning, and repairing a leaking gasket, tubing fitting and seal; tuning to operate over a broader range of proportional band; eliminating an unnecessary valve positioner), and maintain the pneumatic controller according to manufacturer specifications to ensure that the VOC emissions are minimized.

(4) Within two years of the effective date, the owner or operator's data systems shall contain the following for each in-service natural gas-driven pneumatic controller[140]:

(a) pneumatic controller unique identification number;

(b) type of controller (continuous or intermittent);

(c) if continuous, design continuous bleed rate in standard cubic feet per hour;

(d) if intermittent, bleed volume per intermittent bleed in standard cubic feet; and

(e) if continuous, design annual bleed rate in standard cubic feet per year.

(5) Upon the effective date for the facility in 20.2.50.116 NMAC, the owner or operator of a natural gas-driven pneumatic diaphragm pump shall, on a monthly basis, conduct an AVO or OGI inspection and shall also inspect the pneumatic pump and perform necessary maintenance, and maintain the pneumatic pump according to manufacturer specifications to ensure that the VOC emissions are minimized.[141]

(6) The owner or operator of a natural gas-driven pneumatic controller shall comply with the requirements in Paragraph (3) of Subsection C or Subsection D of 20.2.50.116 NMAC, applicable to the facility type at which the pneumatic controller is installed on the effective date specified in section 20.2.50.116 NMAC. During instrument inspections, operators shall use RM 21, OGI, or alternative instruments used under Subsection D of 20.2.50.116 NMAC to verify that intermittent controllers are not emitting when not actuating. Any intermittent controller emitting when not actuating shall be repaired consistent with Subsection E of 20.2.50.116 NMAC.[142]

---

[139] Change aligns the start date with completion of the inventory.

[140] Paragraph (3) of Subsection A of proposed 20.2.50.112 NMAC provides two years to establish the data system. This provision needs to be consistent as data cannot be recorded until the system is in place. Mr. Smitherman indicated two years would be needed and Ms. Kuehn agreed that NMED's experience is that such systems take more than a year to set up. Bisbey-Kuehn testimony, Transcript 5:1370:3-8; *see also* Smitherman testimony, Tr. 5:1427:21-5:1428:25; Brown testimony, Tr. 5:1437:19-5:1439:11.

[141] This is an LDAR requirement. LDAR on a particular piece of a facility should be started when the facility starts LDAR under proposed 20.2.50.116 NMAC. Piecemeal implementation adds cost, double mobilization, and makes compliance difficult as the full LDAR system is not ready prior to its design and implementation under section 20.2.50.116 NMAC. Smitherman testimony, NMOGA Exhibit A1:21:16-39.

[142] This is an LDAR requirement. LDAR on a controllers at a facility should be started when the facility starts LDAR under proposed 20.2.50.116 NMAC. Piecemeal implementation adds cost, double mobilization, and makes compliance difficult as the full LDAR system is not ready prior to its design and implementation under section 20.2.50.116 NMAC. Smitherman testimony, NMOGA Exhibit A1:21:16-39.

(7) Prior to any monitoring event, the owner or operator shall date and time stamp the event, and the monitoring data entry shall be made in accordance with the requirements of this Part.

(8) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) Non-emitting pneumatic controllers and diaphragm pumps are not subject to the recordkeeping requirements in Subsection D of 20.2.50.122 NMAC.

(2) The owner or operator shall maintain a record of the total historic[143] controller count for all controllers at all of the owner or operator's affected facilities that commenced operation before the effective date of this Part. The total controller count must include all emitting and non-emitting pneumatic controllers.

(3) The owner or operator shall maintain a record of the total count of natural gas-driven pneumatic controllers necessary for a safety or process purpose that cannot otherwise be met without emitting VOC.

(4) The owner or operator of a natural gas-driven pneumatic controller subject to the requirements in tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC shall generate a schedule for meeting the compliance deadlines for each pneumatic controller. The owner or operator shall keep a record of the compliance status of each subject controller. On or before January 1, 2024, January 1, 2027 and January 1, 2030, the owner or operator shall make and retain the compliance demonstration set forth in Paragraph (4)(c) of Subsection B of 20.2.50.122 NMAC.[144]

(5) The owner or operator shall maintain an electronic record for each natural gas-driven pneumatic controller. The record shall include the following:

(a) pneumatic controller unique identification number;

(b) time and date stamp, including GPS of the location, of any monitoring;

(c) name of the person(s) conducting the inspection;

(d) AVO or OGI inspection result;

(e) AVO or OGI level discrepancy in continuous or intermittent bleed rate;

(f) record of the controller type, bleed rate, or bleed volume required in Subparagraphs (b), (c), (d), and (e) of Paragraph (4) of Subsection C on 20.2.50.122 NMAC.

(g) maintenance date and maintenance activity; and

(h) a record of the justification and certification required in Subparagraph (c) of Paragraph (4) of Subsection B of 20.2.50.122 NMAC.

(6) The owner or operator of a natural gas-driven pneumatic controller with a bleed rate greater than six standard cubic feet per hour shall maintain a record documenting why a bleed rate greater than six scf/hr is necessary, as required in Subsection B of 20.2.50.122 NMAC. This demonstration shall be completed by July 1, 2023 for controllers with a bleed rate greater than six scf/hr and as necessary for controllers with a bleed rate less than or equal to six scf/hr.[145]

(7) The owner or operator shall maintain a record for a natural gas-driven pneumatic pump with an emission rate greater than zero and the associated pump number at the facility. The record shall include:

(a) for a natural gas-driven pneumatic diaphragm pump in operation less than 90 days per calendar year, a record for each day of operation during the calendar year.

(b) a record of any control device designed to achieve at least ninety-five percent emission reduction, including an evaluation or manufacturer specifications indicating the percentage reduction the control device is designed to achieve.

(c) records of the engineering assessment and certification by a qualified professional or inhouse engineer that routing pneumatic pump emissions to a control device, fuel cell, or process is technically infeasible.

(8) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.122 NMAC - N, XX/XX/2021]

---

[143] Added for consistency with NMOGA's proposed changes.

[144] This provision added to memorialize the compliance demonstration contemplated in new paragraph (4)(c) of Subsection B of 20.2.50.122 NMAC.

[145] Language harmonizes recordkeeping provision with schedule for phase out of High Bleed Controllers while allowing for designation of smaller units, as indicated in Ms. Kuehn's testimony. Bisbey-Kuehn testimony, Tr. 7:2040:17-7:2041:9.

20.2.50.123 STORAGE VESSELS

A. Applicability: New storage vessels with a PTE equal to or greater than two tpy of VOC, existing storage vessels in multi-tank batteries with a PTE equal to or greater than three tpy of VOC, and existing storage vessels in single tank batteries with a PTE equal to or greater than six tpy of VOC are subject to the requirements of 20.2.50.123 NMAC. Storage vessels in multi-tank batteries manifolded together such that all vapors are shared between the headspace of the storage vessels and are routed to a common outlet or endpoint may determine an individual storage vessel PTE by averaging the emissions across the total number of storage vessels. Storage vessels at produced water management units are exempt from this section except as provided in Subsection B of 20.2.50.126 NMAC[146].

B. Emission standards:

(1) An existing storage vessel subject to this Section shall have a combined capture and control of VOC emissions of at least ninety-five percent according to the following schedule. If a combustion control device is used, the combustion device shall have a minimum design combustion efficiency of ninety-eight percent.

(a) By January 1, 2025, an owner or operator shall ensure at least 30% of the company's existing storage vessels are controlled;

(b) By January 1, 2027, an owner or operator shall ensure at least an additional 35% of the company's existing storage vessels are controlled; and

(c) By January 1, 2029, an owner or operator shall ensure the company's remaining existing storage vessels are controlled.

(2) A new storage vessel subject to this Section shall have a combined capture and control of VOC emissions of at least ninety-five percent upon startup. If a combustion control device is used, the combustion device shall have a minimum design combustion efficiency of ninety-eight percent.[147]

(3) The emission standards in Subsection B of 20.2.50.123 NMAC cease to apply to a storage vessel if the actual annual VOC emissions decrease to less than two tpy.

(4) If a control device is not installed by the date specified in Paragraphs (1) and (2) of Subsection B of 20.2.50.123 NMAC, an owner or operator may comply with Subsection B of 20.2.50.123 NMAC by shutting in the well supplying the storage vessel by the applicable date, and not resuming production from the well until the control device is installed and operational.

(5) The owner or operator of a new or existing storage vessel with a thief hatch shall ensure that the thief hatch is capable of opening sufficiently to relieve overpressure in the vessel and to automatically close once the vessel overpressure is relieved. Any pressure relief device installed must automatically close once the vessel overpressure is relieved.

(6) An owner or operator complying with Paragraphs (1) and (2) of Subsection B of 20.2.50.123 NMAC through use of a control device shall comply with the control device operational requirements in 20.2.50.115 NMAC.

C. Storage vessel measurement requirements: Owners and operators of new storage vessels required to be controlled pursuant to this Part at well sites, tank batteries, gathering and boosting stations, or natural gas processing plants shall use a storage vessel measurement system to determine the quantity of liquids in the storage vessel(s). New tank batteries receiving an annual average of 200 bbls oil/day or more with available grid power shall be outfitted with a lease automated custody transfer (LACT) unit(s).

(1) The owner or operator shall keep thief hatches (or other access points to the vessel) and pressure relief devices on storage vessels equipped with a storage vessel measurement system [148]closed and latched during activities to determine the quantity of liquids in the storage vessel(s), except as necessary for custody

---

[146] This language is added to clarify how proposed 20.2.50.123 and 20.2.50.126 NMAC work together for storage vessels at produced water management units. As the testimony showed, storage vessels or tanks at these facilities have difficult to predict potential to emit, may have unrealistically high potential to emit compared to actual VOCs lost from the process, and may require extensive supplemental fuel to control, with adverse ozone effects. Therefore, it is proposed to address these storage vessels first under 20.2.50.126. If 20.2.50.126 determines that section 20.2.50.123 controls are appropriate, then they would comply.

[147] Meyer rebuttal testimony, NMOGA Exhibit 42:11:34-37, 12:1-17. Mr. Meyer testified that a control device can be designed with 98% control, but that level of control cannot be guaranteed during operation.

[148] As written, the provision applied the prohibition on opening the thief hatch to storage vessels without a storage vessel measurement system. Alternatively, "new" could be added before storage vessel in line 29. NMOGA has proposed this language to use the storage vessel measurement system whenever available.

transfer. Tank batteries equipped with LACT units shall use the LACT unit measurements and samples[149] in lieu of opening the thief hatch to test quantity and quality except in case of malfunction. Nothing in this paragraph shall be construed to prohibit the opening of thief hatches, pressure relief devices, or any other openings or access points to perform maintenance or similar activities designed to ensure the safety or proper operation of the storage vessel(s) or related equipment or processes. Where opening a thief hatch is necessary, owners and operators of new and existing storage vessels shall minimize the time the thief hatch is open.

(2) The owner or operator may inspect, test, and calibrate the storage vessel measurement system either semiannually, or as directed by the Bureau of Land Management (see 43 C.F.R. Section 374.6(b)(5)(ii)(B) (November 17, 2016)) or system manufacturer. Opening a thief hatch if required to inspect, test, or calibrate the vessel measurement system is not a violation of Paragraph (1) of this Subsection.

(3) The owner or operator shall install signage at or near the storage vessel that indicates which equipment and method(s) are used and the appropriate and necessary operating procedures for that system.

(4) The owner or operator shall develop and implement an annual training program for employees and third parties conducting activities subject to this Subsection that includes, at a minimum, operating procedures for each type of system.

(5) The owner or operator must make and retain the following records for at least two (2) years and make such records available to the department upon request:

(a) date of construction of the storage vessel or facility;

(b) description of the storage vessel measurement system used to comply with this Subsection;

(c) date(s) of storage vessel measurement system inspections, testing, and calibrations that require opening the thief hatch pursuant to Paragraph (1[150]) of this Subsection;

(d) manufacturer specifications regarding storage vessel measurement system inspections and/or calibrations, if followed pursuant to Paragraph (3) of this Subsection; and

(e) records of the annual training program, including the date and names of persons trained.

D. **Monitoring requirements:** The owner or operator of a storage vessel shall:

(1) Effective January 1, 2023, monthly, monitor, or calculate or estimate, the total monthly liquid throughput (in barrels) and the upstream separator pressure (in psig) if the storage vessel is directly downstream of a separator. When a storage vessel is unloaded less frequently than monthly, the throughput and separator pressure monitoring shall be conducted before the storage vessel is unloaded;

(2) conduct an AVO inspection on a weekly basis. If the storage vessel is unloaded less frequently than weekly, the AVO inspection shall be conducted before the storage vessel is unloaded;

(3) inspect the storage vessel monthly to ensure compliance with the requirements of 20.2.50.123 NMAC. The inspection shall include a check to ensure the vessel does not have a leak;

(4) prior to any monitoring event, the owner or operator shall date and time stamp the event, and the monitoring data entry shall be made in accordance with the requirements of this Part.

(5) comply with the monitoring requirements in 20.2.50.115 NMAC if using a control device to comply with the requirements in Paragraphs (1) and (2) of Subsection B of 20.2.50.123 NMAC; and

(6) comply with the monitoring requirements of 20.2.50.112 NMAC.

E. **Recordkeeping requirements:**

(1) Effective January 1, 2023, monthly, the owner or operator shall maintain a record for each storage vessel of the following:

(a) unique identification number and location (latitude and longitude);

(b) monitored, calculated, or estimated monthly liquid throughput;

(c) the upstream separator pressure, if a separator is present;

(d) the data and methodology used to calculate the actual emissions of VOC (tpy);

(e) the controlled and uncontrolled VOC emissions (tpy); and

(f) the type, make, model, and identification number of any control device.

(2) A record of liquid throughput shall be verified by dated liquid level measurements, a dated delivery receipt from the purchaser of the hydrocarbon liquid, the metered volume of hydrocarbon liquid sent

---

[149] Language added to clarify that the LACT unit does not give readouts on quality, but enables quality samples to be taken of the oil passing through the unit without opening the thief hatch. *See generally* Smitherman rebuttal testimony, NMOGA Exhibit 41:10:38 - 12:15

[150] It appears that this is a typo in the original.

downstream, or other proof of transfer.

(3) A record of the inspections required in Subsections C and D of 20.2.50.123 NMAC shall include:

(a) the date and time stamp, including GPS of the location, of the inspection;

(b) the person(s) conducting the inspection;

(c) a description of any problem observed during the inspection; and

(d) a description and date of any corrective action taken.

(4) An owner or operator complying with the requirements in Paragraphs (1) and (2) of Subsection B of 20.2.50.123 NMAC through use of a control device shall comply with the recordkeeping requirements in 20.2.50.115 NMAC.

(5) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

F. **Reporting requirements:**

(1) An owner or operator complying with the requirements in Paragraphs (1) and (2) of Subsection B of 20.2.50.123 NMAC through use of a control device shall comply with the reporting requirements in 20.2.50.115 NMAC.

(2) The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.123 NMAC - N, XX/XX/2021]

20.2.50.124 WELL WORKOVERS[151]

A. **Applicability:** Workovers performed at oil and natural gas wells are subject to the requirements of 20.2.50.124 NMAC as of the effective date of this Part.

B. **Emission standards:** The owner or operator of an oil or natural gas well shall use the following best management practices during a workover to minimize emissions, consistent with the well site condition and good engineering or operational practices:

(1) reduce wellhead pressure before blowdown to minimize the volume of natural gas vented;

(2) monitor manual venting at the well until the venting is complete; and

(3) route natural gas to the sales line, if possible.

C. **Monitoring requirements:**

(1) The owner or operator shall monitor the following parameters during a workover:

(a) wellhead pressure;

(b) flow rate of the vented natural gas (to the extent feasible); and

(c) duration of venting to the atmosphere.

(2) The owner or operator shall calculate the estimated volume and mass of VOC vented during a workover.

(3) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. **Recordkeeping requirements:**

(1) The owner or operator shall keep the following record for a workover:

(a) unique identification number and location (latitude and longitude) of the well;

(b) date the workover was performed;

(c) wellhead pressure;

(d) flow rate of the vented natural gas to the extent feasible, and if measurement of the flow rate is not feasible, the owner or operator shall use the maximum potential flow rate in the emission calculation;

(e) duration of venting to the atmosphere;

(f) description of the best management practices used to minimize release of VOC emissions before and during the workover;

(g) calculation of the estimated VOC emissions vented during the workover based on the duration, volume, and gas composition; and

(h) the method of notification to the public and proof that notification was made to the affected public.

---

[151] NMOGA has argued this section should be stricken in its entirety. *See* NMOGA Final Brief.

(2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements

(1) The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

(2) If it is not feasible to prevent VOC emissions from being emitted to the atmosphere from a workover event, the owner or operator shall notify by certified mail, or by other effective means of notice so long as the notification can be documented, all residents located within one-quarter mile of the well of the planned workover at least three calendar days before the workover event.

(3) If the workover is needed for routine or emergency downhole maintenance to restore production lost due to upsets or equipment malfunction, the owner or operator shall notify all residents located within one-quarter mile of the well of the planned workover at least 24 hours before the workover event.[152]

[20.2.50.124 NMAC - N, XX/XX/2021]

20.2.50.125 SMALL BUSINESS FACILITIES

A. Applicability: Small business facilities as defined in this Part are subject to the requirements of 20.2.50.125 NMAC.[153]

B. General requirements:

(1) The owner or operator shall ensure that all equipment is operated and maintained consistent with manufacturer specifications, and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications and maintenance practices on file and make them available to the department upon request.

(2) The owner or operator shall calculate the VOC and NO_x emissions from the facility on an annual basis. The calculation shall be based on the actual production or processing rates of the facility.

(3) The owner or operator shall maintain a database of company-wide VOC and NO_x emission calculations for all subject facilities and associated equipment and shall update the database annually.

(4) The owner or operator shall comply with Paragraph (9) of Subsection A of 20.2.50.112 NMAC if requested by the department.

C. Monitoring requirements: The owner or operator shall comply with the requirements in Subsections C or D of 20.2.50.116 NMAC.

D. Repair requirements: The owner or operator shall comply with the requirements of Subsection E of 20.2.50.116 NMAC.

E. Recordkeeping requirements: The owner or operator shall maintain the following electronic records for each facility:

(1) annual certification that the small business facility meets the definition in this Part;

(2) calculated annual VOC and NO_x emissions from each facility and the company-wide annual VOC and NO_x emissions for all subject facilities; and

(3) records as required under Subsection F of 20.2.50.116 NMAC.

F. Reporting requirements: The owner or operator shall submit to the department an initial small business certification within sixty days of the effective date of this Part, and by March 1 each calendar year thereafter. The certification shall be made on a form provided by the department. The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

G. Failure to comply with 20.2.50.125 NMAC: Notwithstanding the provisions of Section 20.2.50.125 NMAC, a source that meets the definition of a small business facility can be required to comply with the other Sections of 20.2.50 NMAC if the Secretary finds based on credible evidence that the source (1) presents an imminent and substantial endangerment to the public health or welfare or to the environment; (2) is not being operated or maintained in a manner that minimizes emissions of air contaminants; or (3) has violated any other requirement of 20.2.50.125 NMAC.

---

[152] Davis testimony, IPANM Exhibit 2:19:2-16. Mr. Davis testified that a requirement to notify the adjacent residents via certified mail three days prior would delay the repair and restoration of production while making the activities less efficient and ultimately not result in any reduction of VOC emissions.

[153] Davis rebuttal testimony, IPANM Exhibit 10:28:10-22, 29:1-2. Mr. Davis testified that the cost of compliance with the proposed rule will disproportionately impact small business and lead to the premature abandonment of wells. Moving back to the stripper well and low PTE structure of the pre-proposal draft, while including the applicability of LDAR and the other requirements ensures that all wells are subject to a baseline set of requirements while not overburdening the stripper wells in the state. *See also* Tr. 3:899-912.

[20.2.50.125 NMAC - N, XX/XX/2021]

20.2.50.126 PRODUCED WATER MANAGEMENT UNITS

A. Applicability: Produced water management units as defined in this Part and their associated storage vessels are subject to 20.2.50.126 NMAC and shall comply with these requirements no later than 180 days after the effective date of this Part.

B. Emission standards:

(1) The owner or operator shall use good operational or engineering practices to minimize emissions of VOC from produced water management units (PWMU) and their associated storage vessels.

(2) The owner or operator shall not allow any transfer of untreated produced water to a PWMU without first processing and treating the produced water in a separator and/or storage vessel to minimize entrained hydrocarbons.

(3) Within two years of the effective date of this Part for storage vessels associated with existing PWMUs, or upon startup for storage vessels associated with new PWMUs, the owner or operator shall either:[154]

(a) control such storage vessels in accordance with the requirements of Section 20.2.50.123 NMAC that are applicable to tank batteries; or

(b) submit a VOC minimization plan to the department demonstrating that controlling VOC emissions from storage vessels associated with the PWMU in accordance with the requirements of Section 20.2.50.123 NMAC is technically infeasible without supplemental fuel. The plan shall state the good operational or engineering practices used to minimize VOC emissions. The plan shall be enforceable by the department upon submission. The department may require revisions to the plan, and must approve any proposed revisions to the plan.

C. Monitoring requirements: The owner or operator shall:

(1) develop a protocol to calculate the VOC emissions from each PWMU. The protocol shall include at a minimum: produced water throughput monitoring, semi-annual sampling and analysis of the liquid composition, hydrocarbon measurement method(s), representative sample size, and sample chain of custody requirements. [155]

(2) calculate the monthly total VOC emissions in tons from each unit with the first month of emission calculations beginning within 180 days of the effective date of this Part;

(3) monthly, monitor the best management and good operational or engineering practices implemented to reduce emissions at each unit to ensure and demonstrate their effectiveness;

(4) upon written request by the department, sample the PWMU to determine the VOC content of the liquid; and

(5) comply with the monitoring requirements of 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator shall maintain the following electronic records for each PWMU:

(a) unique identification number and UTM coordinates of the PWMU;

(b) the good operational or engineering practices used to minimize emissions of VOC from the unit;

(c) the protocol, and the results of the sampling conducted in accordance with the protocol; and

(d) a record of the annual total VOC emissions from each unit.

(2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.126 NMAC - N, XX/XX/2021]

20.2.50.127 PROHIBITED ACTIVITY AND CREDIBLE EVIDENCE

A. Failure to comply with the emissions standards, monitoring, recordkeeping, reporting or other

[154] This language is responsive to extensive testimony that supplemental fuel may be needed to control storage vessels associated with produced water management units. *See, e.g.,* Kim testimony, Tr. 7:2290:6-13. This may not be technically feasible and may not provide a net environmental benefit. Kim testimony, Tr. 7:2290:6-13.

[155] NMOGA supports CDG's proposed clarification circulated to the parties on December 16, 2021.

requirements of this Part within the timeframes specified shall constitute a violation of this Part subject to enforcement action under Section 74-2-12 NMSA 1978.

B. If credible evidence or information obtained by the department or provided to the department by a third party indicates that a source is not in compliance with the provisions of this Part that evidence or information may be used by the department for purposes of establishing whether a person has violated or is in violation of this Part.[156]

HISTORY OF 20.2.50 NMAC: [**RESERVED**]